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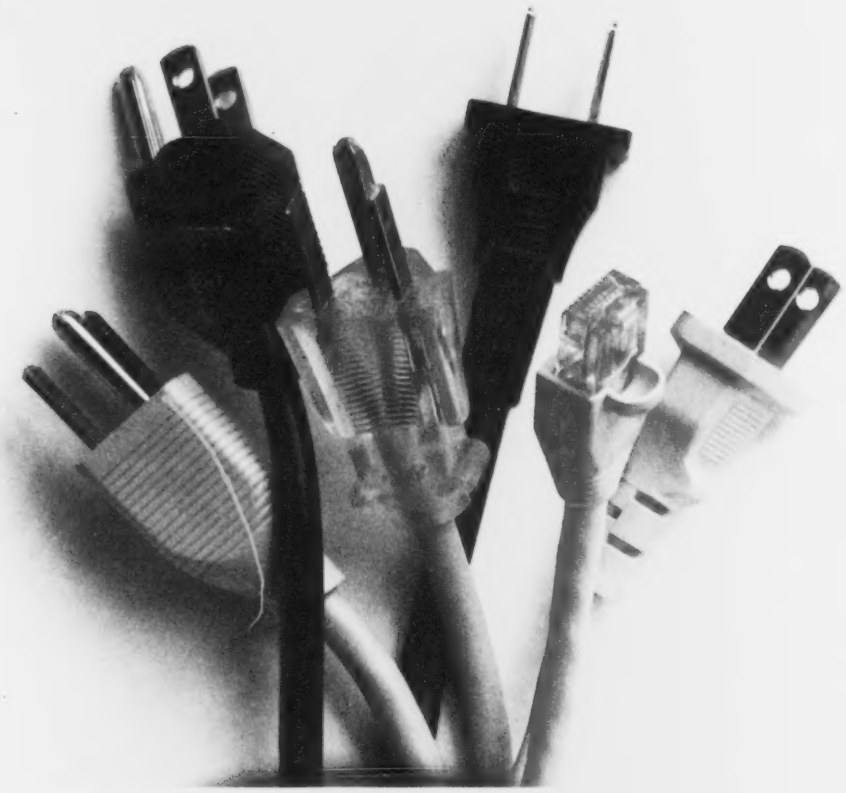
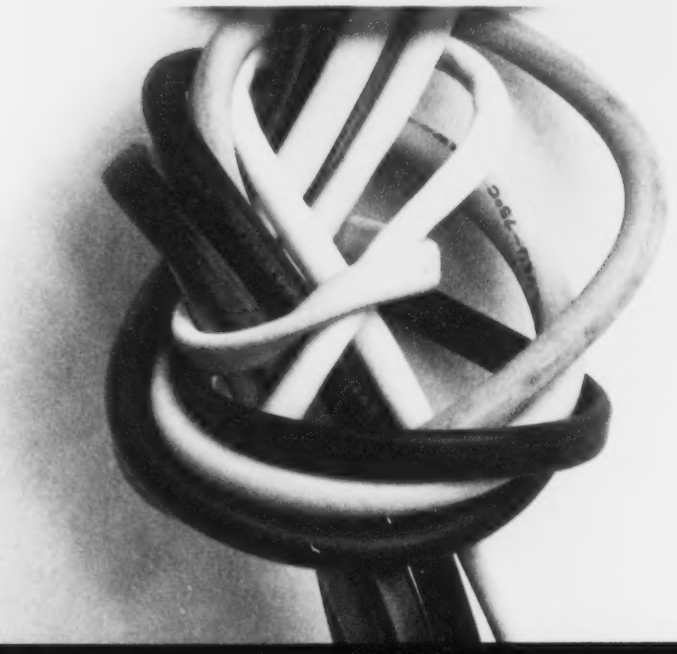


Managing a Complex Energy System

Annual Energy Conservation Progress Report – 2010 (Volume One)



Environmental
Commissioner
of Ontario

Commissaire à
l'environnement
de l'Ontario

Gord Miller, B.Sc., M.Sc.
Commissioner

Gord Miller, B.Sc., M.Sc.
Commissaire

June 2011

The Honourable Steve Peters
Speaker of the Legislative Assembly of Ontario

Room 180, Legislative Building
Legislative Assembly
Province of Ontario
Queen's Park

Dear Speaker:

In accordance with Section 58.1 of the *Environmental Bill of Rights, 1993*, I am pleased to present to you Volume One of the Annual Energy Conservation Progress Report – 2010 of the Environmental Commissioner of Ontario for your submission to the Legislative Assembly of Ontario.

The Annual Energy Conservation Progress Report – 2010 is my independent review of the Ontario government's progress in conserving energy, and will be issued in two separate documents. This first volume covers the broader policy framework affecting energy conservation in Ontario. The second volume will describe initiatives underway, assess energy savings derived from these initiatives and measure progress on meeting targets.

Sincerely,

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Environmental Commissioner of Ontario

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Acronyms

BAP	Board-Approved Program
CDM	Conservation and Demand Management
DSM	Demand-Side Management
EBR	*Environmental Bill of Rights, 1993*
ECO	Environmental Commissioner of Ontario
ECPA	*Energy Consumer Protection Act, 2010*
EM&V	Evaluation, Measurement and Verification
FIT	Feed-in Tariff
GEGEA	*Green Energy and Green Economy Act, 2009*
GHG	Greenhouse Gas
GST	Goods and Services Tax
HESP	Home Energy Savings Program
HST	Harmonized Sales Tax
IESO	Independent Electricity System Operator
IPSP	Integrated Power System Plan
kV	Kilovolt
kW	Kilowatt
kWh	Kilowatt-hour
LDC	Local Distribution Company
LTEP	Long-Term Energy Plan
MMAH	Ministry of Municipal Affairs and Housing
MW	Megawatt
MWh	Megawatt-hour
OCEB	Ontario Clean Energy Benefit
OEB	Ontario Energy Board
OPA	Ontario Power Authority
PV	Photovoltaic
RPP	Regulated Price Plan
RTA	*Residential Tenancies Act, 2006*
SGWG	Smart Grid Working Group
TOU	Time-of-Use (pricing)
TWh	Terawatt-hour

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1: Executive Summary

Under the *Environmental Bill of Rights, 1993*, the Environmental Commissioner of Ontario (ECO) reports annually to the Legislative Assembly of Ontario on the province's progress in energy conservation.

This report is the first volume of the 2010 energy conservation report and reviews policy developments. The report concentrates on electricity policy because most activity has been centred on the continuing reform of electricity regulation. Four electricity topics that dominated the policy agenda are covered. An analysis of an Ontario Energy Board (OEB or the "Board") decision to not increase the conservation budgets of natural gas distributors is also included. One barrier topic was selected for in-depth discussion: the report reviews barriers to alternative heating and cooling systems that use renewable energy sources.

The Long-Term Energy Plan

In 2010, the government restarted the development of the Integrated Power System Plan (IPSP). This was long overdue as the regulatory framework has entered its fifth year without an IPSP, formally approved as required in law. An approved IPSP is needed by organizations whose actions help meet conservation targets and objectives set by government. The IPSP is also necessary to provide the detailed assumptions and data that were not contained in the Long-Term Energy Plan (LTEP) so that the veracity and feasibility of the LTEP can be scrutinized.

It is commendable that the government sought public comment through the Environmental Registry before issuing the LTEP. The Ministry of Energy, however, has not posted a decision notice on the Registry. Therefore, it is not known how the wide-ranging comments were considered.

It is a positive step that the government acted on a 2009 ECO recommendation by establishing electricity consumption (kilowatt-hour) targets, in addition to peak reduction targets, to support its policy to build a conserver culture. The ECO believes, however, that the Ministry of Energy should clarify the specific technical details of how peak demand and consumption targets, established for the 2011 to 2014 period and the LTEP's planning horizon, are measured because their interpretation is ambiguous.

Previously, the regulatory framework included only demand (kilowatt or kW) targets. These have a more narrow focus and concentrate conservation activity on the dozen or so hours in a year when demand on the electricity system peaks (reaches the highest amounts consumed during the year). With the LTEP now including two types of targets, the approach to conservation is more comprehensive. This will reduce the amount of new generating stations and transmission and distribution lines that must be built, and provides more environmental benefits. Consumption targets also better reflect the design of many of the conservation programs available in Ontario (e.g., home and business retrofits, standards and rebates for high efficiency appliances), and this helps ensure the programs will continue to be offered.

The ECO agrees with the vision – low-carbon generators connected to a smart grid that will facilitate conservation – contained in the LTEP. This vision, however, was poorly communicated. The LTEP did not adequately explain the difficult trade-offs that are necessary when choosing among types of generation. In particular, an opportunity was missed to educate the public on the expected costs of renewable and conventional generation, possibly leaving the public vulnerable to misinformation and not supportive of the vision. Finally, the LTEP is an energy plan in name but is an *electricity* plan in reality. Ontario needs an energy plan and, as the ECO recommended in 2009, the province needs a multi-fuel conservation strategy that addresses all energy sources.

Pricing Policy

The LTEP estimates that electricity prices will rise by 30 per cent in real terms between 2010 and 2014. Several changes to pricing policy were made, through the introduction of tax credits and an electricity bill rebate, to shelter eligible consumers from higher energy costs. Contained in the 2010 Ontario Budget were: the Ontario Energy and Property Tax Credit and the Northern Ontario Energy Credit. In the 2010 Fall Economic Statement (and LTEP), a 10 per cent price rebate on electricity bills called the Ontario Clean Energy Benefit (OCEB) was introduced.

These financial measures have different effects on conservation. The ECO supports the tax credits because they maintain a price signal that reflects the true cost of energy, while protecting vulnerable consumers, and thus do not undermine conservation. Conversely, the ECO disagrees with implementation of the OCEB. It is a perverse incentive that undermines conservation efforts.

One estimate of its effect is to increase overall electricity consumption by more than one per cent. This would negate about one-third of the savings that conservation programs are expected to provide between 2011 and 2014.

In 2010, a regulation was made that changed the method by which certain consumers (e.g., larger industrial plants, universities) paid for the electricity they consumed. These consumers are billed through a charge known as the Global Adjustment but the method of billing was changed from a straight volumetric payment to one based on electricity consumed during the five highest system peak hours of the year. This effectively introduced a form of critical peak pricing that applies very high prices during a few hours of very high demand when the delivery system is under stress. The Independent Electricity System Operator estimates that this might reduce peak system demand by 500 megawatts and avoid nearly one-half billion dollars of new investment while reducing prices for all consumers by about one-half cent per kilowatt-hour.

The ECO supports this incentive to reduce peak demand, with some qualifications. The ECO urges the government to expand critical peak pricing to other smaller volume consumers to encourage conservation on their part and adjust some inequities in the allocation of costs in the Global Adjustment.

The government also passed legislation to clarify rules around individual metering of multi-unit residential buildings, known as suite metering, in buildings that would otherwise be served by a single bulk meter making it difficult for individual occupants to measure their own electricity use and take actions to conserve. The ECO approves of these changes, which ensure that more Ontario consumers will receive price signals that reflect their consumption and provide incentives for energy conservation.

The Conservation and Demand Management Code for Electricity Distributors

Two program delivery frameworks governed conservation in the last half of the previous decade. A third, which mandates electricity distributors to deliver programs to meet assigned conservation targets as a licence condition, will be in effect over the next four years.

From 2005 to 2010, the role of distributors has varied from innovator and leader in Conservation and Demand Management (CDM) to program delivery agents for the Ontario Power Authority (OPA). A new CDM framework has been implemented for the next four years. For the first time, electricity distributors are mandated, as a license condition, to deliver CDM programs to meet their conservation targets.

A new CDM Code governs distributors' conservation activities. Most distributors will meet their targets by delivering both self-designed programs and contracting to deliver the OPA's province-wide programs. All electricity savings will be verified by a third-party and distributors will be eligible to receive financial incentives for meeting or exceeding their targets.

The ECO notes three concerns about the Code. Under the Code, a distributor must prove centrality (e.g., it contributed at least 50 per cent of the budget, initiated the program) before it can claim all the electricity savings. The ECO is concerned the centrality principle may be unnecessarily onerous and act as a disincentive to co-operation with other electric and natural gas distributors or organizations.

Secondly, the ECO is concerned contracts between distributors and the OPA do not allow distributors the flexibility to customize province-wide programs, if needed. The ECO also believes that the Code's definition of duplication is overly restrictive, may be contrary to the spirit of the *Green Energy and Green Economy Act, 2009*, and could inhibit distributors from developing innovative conservation programs.

Finally, there are no LDC targets or stated commitment to their role in CDM beyond the time period of the current framework. To ensure momentum is sustained, a process to review and prepare for the next CDM framework should be established well before the end of 2014.

Natural Gas DSM Budgets

The OEB recently announced its determination that the demand-side management (i.e., conservation) budgets of Ontario's natural gas distributors would be limited to their current levels for the next three years. In its 2009 report, the ECO stated support for increasing these budgets to bring them into line with budget levels in neighbouring jurisdictions, and thus disagrees with

the Board's recent decision. The Board presented four arguments for its determination and the ECO offers alternative rebuttal arguments.

Briefly, the ECO's position is the following: conservation provides system benefits that help all gas consumers and environmental benefits for all Ontarians from reduced emissions. Limiting conservation funding means these benefits are lost. Conservation remains a very cost-effective strategy and offers between 7 and 10 dollars, depending on the program, for every dollar that natural gas distributors spend on conservation. The rules of how conservation is funded limit the amount of cross-subsidies of program participants by non-participants, and reduce any inequities. The end of some government programs is not a signal by government that utility funded programs should also be limited. Indeed, communication issued by the Minister of Energy indicates that the government believes gas distributors should expand conservation activities.

The combined effect of budget decisions on conservation by the government and the OEB is to reduce spending on natural gas conservation to very low levels, which is unfortunate given the large contribution of natural gas to both Ontario's total energy consumption and its greenhouse gas (GHG) emissions.

Ontario's Activities to Build the Smart Grid

The smart grid is a recently-developed term that refers to the next generation of electricity delivery infrastructure where new technologies (e.g., storage, distributed generation, smart meters and two-way information flow) will work together. One of the benefits is the potential to enhance the amount of conservation, renewable generation and distributed energy, which makes the system more efficient.

Ontario recently passed enabling legislation and provided ministerial direction to facilitate this modernization of the grid but there are planning, operational and financial challenges to be met that are faced by all organizations (e.g., transmitters, distributors, the system operator, the regulator, government). In addition, working groups, forums, research funds and centres have been established and pilot projects are planned.

At this early stage, the ECO's principle concern is that a single entity with the perspective of the electricity system as a whole is needed to lead this implementation. The government should produce a discussion paper and consult with the public regarding who should lead implementation of the smart grid and how this can best be accomplished.

There is a regulatory issue that should be immediately resolved: the OEB should address distribution utility concerns that the current regulatory environment does not facilitate their ability to fund smart grid investments to reduce line losses (electricity that is lost in the delivery of power to the end user).

Barriers to Alternative Heating and Cooling

The ECO is mandated to identify and review barriers that prevent the reduction or more efficient use of energy. This report focuses on barriers to the uptake of alternative heating and cooling technologies, such as solar and geothermal. The report makes several suggestions for addressing barriers.

The Ontario Building Code, which currently does not include provisions for alternative energy systems, should be updated to facilitate builders' use of alternative energy systems. The ECO suggests that simple methods could be developed for builders of houses with alternative energy systems to demonstrate compliance with the Building Code.

In current policy that governs the development of programs to promote alternative heating and cooling technologies by electricity distributors, there is a hurdle related to the cost-benefit test that distributors must pass to receive OEB approval of programs. The government, with the OPA and Board's advice, should act to address this barrier.

Land use planning affects energy use, but alternative energy is currently poorly integrated into planning processes at the neighbourhood level. The ECO believes that integrated community energy planning should be pursued.

Finally, the report urges the government to correct the imbalance between incentives offered for solar heating compared to financial assistance provided for solar electricity generation (photovoltaic or PV systems). Since PV incentives are currently more

attractive than those for solar thermal, homeowners are more likely to use their limited property space to install PV systems. While this does assist in meeting government targets for renewable generation, solar thermal energy offers environmental benefits that can help Ontario meet its GHG reduction targets.

To address our findings, this report makes the following recommendations:

1. **The ECO recommends that the Ministry of Energy clarify how the peak demand and consumption targets contained in the Long-Term Energy Plan and Conservation and Demand Management Directive are measured.**
2. **The ECO recommends that the Ministry of Energy build upon the work completed in the Long-Term Energy Plan and produce a comprehensive multi-fuel energy plan.**
3. **The ECO recommends that the Ministries of Energy, Revenue, and Finance improve the design of the Ontario Clean Energy Benefit so that any transitional assistance on electricity bills does not act as a disincentive to conservation.**
4. **The ECO recommends that the Ministry of Energy initiate the next Conservation and Demand Management framework, which would include guaranteed funding, by January 1, 2014.**
5. **The ECO recommends that the Ministry of Energy clarify the appropriate roles of the government and gas utilities in funding natural gas conservation, with the goal of increasing overall funding.**
6. **The ECO recommends that the Ontario Energy Board encourage and facilitate smart grid investments that reduce line losses, putting these investments on an equal footing with conservation investments.**
7. **The ECO recommends that the Ministry of Energy adjust the relative financial incentives available for solar thermal and solar photovoltaic in residential buildings to appropriately reflect the economic and environmental benefits of each technology.**

2: Introduction

2.1 The ECO's Reporting Mandate and Approach

As required under the *Environmental Bill of Rights, 1993* (*EBR*), the Environmental Commissioner of Ontario (ECO) reports annually to the Speaker of the Legislative Assembly of Ontario on: the results of initiatives in Ontario in reducing or making more efficient use of all major sources of energy; the progress in achieving government-established energy conservation targets; and, the barriers to energy conservation and efficiency. Reports are issued biannually as two separate volumes for each year. The first volume focuses on broader policy developments in energy. The second volume analyzes conservation program data, reviews initiatives undertaken and measures progress toward targets.[1]

2.2 Context of the Report

This Volume One report for 2010 focuses on electricity because most of Ontario's energy conservation policy, as in previous years, has been directed toward reform of the regulatory framework for electricity.

In 2010, major reform of the regulatory framework for natural gas conservation was undertaken. It does not receive coverage in this report since the reform is not yet completed. An Ontario Energy Board (OEB or the "Board") consultation[2] to develop natural gas conservation guidelines -- including the issue of increasing conservation budgets of distributors – concluded in late 2010 but the OEB's decision was not yet issued when this report was written and could not be incorporated. As part of the proceedings, the Board issued a letter in April 2011 advising of its determination that conservation budgets of distributors should not be increased. The ECO will fully review these guidelines in a future report. This report includes only an analysis of the OEB's denial of increased funding.

As was the case in 2009, little policy development related to the conservation of oil, propane or transportation fuels was evident in 2010, and consequently review of policy for these fuels was not included in this report.[3]

The politics of electricity remain in flux, and are arguably at a crossroads. It is difficult to predict if current policies will prevail or be abandoned. It is uncertain whether the directional shift to green energy (renewable supply and conservation) will be maintained or whether conservation delivery and planned renewable generation will be adjusted or scaled back.

Surveying the policy process and elements of the electricity framework added in 2010, the ECO contends that the key feature has been the creation of an ever more complex regulatory structure.

Surveying the policy process and elements of the electricity framework added in 2010, the ECO contends that the key feature has been the creation of an ever more complex regulatory structure. The policy has become more complicted, less linear, less resilient and has produced unexpected outcomes.[4] On occasion, policy implementers have been unprepared to respond to these outcomes, and reacted with solutions that further ignore the connectivity that first caused the unexpected outcome. Developments in electricity pricing policy and solar micro-generation are examples of this.

The institutional structure may be fragmenting. Under current policy and legislation, institutional actors (agencies, the regulator, energy companies and government) are given a broad shared responsibility to advance conservation. Rather than contributing to this co-operative mandate, on occasion, individual actors have interpreted the common mandate from a narrow perspective and ignored the functional needs of other actors. This has resulted in delayed progress. Examples of this fragmentation include: protracted efforts of the Ontario Power Authority (OPA) and Local Distribution Companies (LDCs) to agree on design and delivery of new Conservation and Demand Management (CDM) programs; and, the OEB's exacting review of Hydro One's application for CDM programs that require the Board's approval to implement. A regulatory regime may be developing that sets organizations at cross purposes. Looking ahead, if conservation targets are not met, this may induce another response that again ignores connectivity and leads to unintended outcomes.

Finally, Ontarians need to understand the policy if they are to support it. As complexity has deepened, electricity policy has become increasingly reliant on a small group of technical specialists that has access to information. Less proximate stakeholders

and most Ontarians could be better equipped to contribute meaningfully to the policy debate. Misinformed or uninformed, Ontarians may become disengaged, leading to policy failure.[5] The production of this report was sometimes hampered by the need to rely on information guarded by policy makers in the Ministry of Energy and the OPA. In requesting information, the ECO occasionally found them unhelpful. Requests were refused or information was meted out with little background data to assist evaluation. The ECO cannot inform Ontarians and facilitate public debate, per its mandate, without access to detailed information.

It is not clear how or if the province will manage the increased complexity of electricity policy. The ECO's perspective is broad-based and perhaps unique among observers of the electricity sector, enabling us to compare patterns in energy policy with other issues that fall within our broader mandate such as climate change and waste management. The similarities in approach and limited success in managing the complexities are sometimes startling.

This report focuses on what the ECO considers the key elements currently intertwined in this complex structure: the Long-Term Energy Plan; the impact of electricity pricing policy on conservation; the OEB code governing CDM; and, the building of the smart grid.

3: Long-Term Energy Plan

3.1 What is the Long-Term Energy Plan?

Ontario's Long-Term Energy Plan, Building our Clean Energy Future,[6] is a document that was issued by the government in November 2010 to help Ontarians understand the long-term development of Ontario's electricity system. It sets out, at a fairly high level of detail, the investment plans for the power system over the next 20 years. A summary of the highlights of the Long-Term Energy Plan (LTEP or the "Plan") are described below.

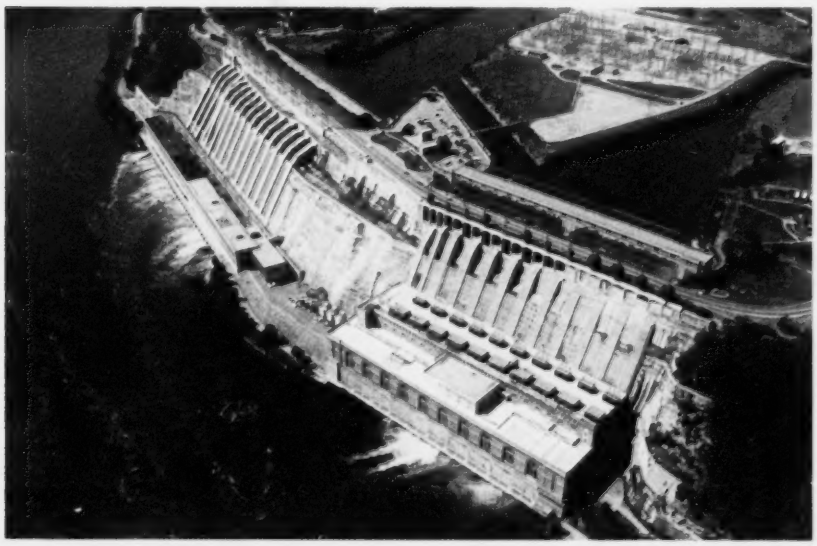
3.2 Changes in Demand and the Supply Mix over the LTEP Planning Period

Electricity demand is forecast to steadily recover from current reduced levels brought about by the global financial crisis of 2008. Demand is forecast to be relatively flat this decade reflecting conservation actions, structural change in Ontario's industrial base and shifts in commercial energy use. The Plan assumes a medium-growth scenario forecasting a 15 per cent increase in demand between 2010 and 2030. Some 146 terawatt-hours (TWh) of electricity are projected to be consumed in 2015, and the LTEP states sufficient flexibility will be created to accommodate higher growth. By 2030, electricity consumption will grow to 165 TWh.[7]

Conservation, which currently accounts for 5 per cent of total "installed capacity" and 4 per cent of total electricity "generated," will triple by 2030.[8]

Ontario's coal-fired plants are targeted to cease burning coal by the end of 2014. By 2013, the Atikokan generating station will be converted to operate on biomass and two units at the Thunder Bay plant will change over to natural gas. Natural gas generation capacity will be maintained at roughly current levels over the LTEP's planning period, although its share of total installed capacity will decline as other supply sources grow. The amount of electricity that gas-fired plants supply to Ontario will decline over the long term, and natural gas will contribute about one-third less of total generation in 2030 than it currently provides.[9, 10] The LTEP maintains nuclear power's contribution to total generation at roughly the current level – it will provide 45 to 50 per cent of Ontario's supply between now and 2030. Nuclear will make up about one-quarter of Ontario's total installed generating capacity in 2030, and supply roughly one-half of all electricity generated in that year – some 10,000 megawatts (MW) of nuclear capacity will be refurbished over the next 10 to 15 years and 2,000 MW of new reactors will be added at the Darlington Nuclear Generating Station.

Electricity generated from renewable sources other than hydroelectric power (i.e., wind, solar and bio-energy), and the amount of generation installed, will grow significantly. Starting from current low levels, the amount of renewable electricity supplied will grow six-fold, and installed capacity more than quadruple by 2030. Hydroelectric power (also a renewable source) will grow slightly from current amounts of capacity and generation.[11]



In terms of the electricity delivery infrastructure, the LTEP indicates that Ontario's transmission and distribution system will be modernized. It promotes building the smart grid as a central tenet of Ontario's electricity future (see section 7). Actions to date have consisted of installing smart meters. The Plan, however, does mention a short list of other actions that are becoming standard items in most jurisdictions pursuing grid modernization, namely: two-way information technologies and real time information to facilitate conservation; utility operations and smart technology to increase the reliability of distributed generation; smart buildings; and, electric vehicle charging.

3.3 The Long-Term Energy Plan and the Integrated Power System Plan

The LTEP is closely tied to the Integrated Power System Plan (IPSP),[12] and it is worth clarifying the development of these two plans to minimize confusion between them. The IPSP – the 20-year plan for designing Ontario's electricity system – is a document that is required by law to be produced by the OPA and updated every three years.[13] The OPA must follow any directives issued by the Minister of Energy that provide policy guidance (known as Supply Mix Directives). The IPSP must be approved by the OEB.

The original or first IPSP was developed by the OPA and submitted to the OEB for approval in 2007. It responded to a Supply Mix Directive issued by the Minister in 2006, directing the OPA to produce the IPSP. The first iteration of the IPSP (IPSP-2007, now referred to as IPSP I by the OPA) contained targets for electricity conservation and the installation of renewable generation capacity, as well as the amounts of conventional generation needed. In 2007, the government did not issue a long-term energy plan.[14]

A new Supply Mix Directive was issued by the Minister to accompany the release of the LTEP, and this directive contained new conservation and renewable capacity targets. The directive hews closely to the LTEP and its elements are identical to the Plan's key features. Sections of the directive dealing with forecast demand, expected conservation achievements, capacity additions of various types of supply, new transmission, and coal phase-out, exactly reflect the terms of the LTEP. When creating the IPSP-2007, the intention was that, upon its approval, the OPA would have the authority to procure the supply and demand resources described in the IPSP, independent of government. Whether that remains a feature of the updated IPSP is an open question. In comparison with the 2006 Supply Mix Directive that preceded the IPSP-2007, the new Supply Mix Directive is more detailed and prescriptive, often directing the OPA to pursue specific projects, instead of simply setting goals and leaving it to the OPA to find the best way to achieve them.

The LTEP can be seen as the plain-language description of the government's intentions, and the Supply Mix Directive is the formal legal guidance that the OPA uses to produce the IPSP. The IPSP will provide a more detailed description of how to achieve the electricity targets described in the LTEP. The OPA has started to prepare the 2011 iteration of the IPSP (IPSP-2011, now referred to as IPSP II by the OPA), and will consult on it in the second quarter of 2011. The Minister issued a letter of direction instructing the OEB to carry out a review of the IPSP no later than one year after the OPA submits it for approval.

3.3.1 Consultation on Ontario's Future Electricity System

The Minister of Energy announced, on September 20, 2010, that the government would *update*[15] its long-term energy plan and would consult on the choices for development of the province's electricity system. The public was asked to comment on nine broad questions, which were posted on the ministry's website.[16] Consultations with energy stakeholders and agencies were also undertaken by ministry officials. There was a wide range of opinion expressed on the questions posed in the 2,500 comments, 33 written submissions and 39 stakeholder consultation sessions. Since the Long-Term Energy Plan (LTEP) is closely integrated with the Integrated Power System Plan (IPSP), the ECO will review this input in a future report as part of a review of the updated IPSP that is expected to be delivered in late 2011.

Following the gathering of feedback, on November 23, 2010, the LTEP was released and a draft Supply Mix Directive was posted as a proposal notice for public comment on the Environmental Registry.[17] The government signalled that, once finalized, the directive would be issued to the Ontario Power Authority (OPA) which would consult to update the existing IPSP.[18] The ministry received 379 comments on the proposal posting. At the time of writing this report, the ministry had not posted a decision notice on the Environmental Registry related to the Supply Mix Directive, and it is unknown how these comments were considered.

Despite the fact that no decision was posted on the Environmental Registry, the finalized Supply Mix Directive was issued to the OPA on February 17, 2011. It replaces previous Supply Mix Directives issued in June 2006 and September 2008. There is no substantive difference between the draft and final Supply Mix Directives.[19]

3.4 Targets of the Long-Term Energy Plan

Table 1 shows several targets contained in both the LTEP and Supply Mix Directive that now govern conservation and compares these targets to those in the IPSP-2007. The LTEP advances the approach to conservation targets contained in the IPSP-2007 by adding electricity consumption reduction targets in TWh. Previously, the government had set only peak demand reduction targets in MW,[20] and the IPSP-2007 contained no consumption targets. The LTEP also contains more interim targets than did the IPSP-2007.

Table 1: Conservation Targets

	IPSP-2007	LTEP	
Year	Peak Demand Reduction Target (MW)	Peak Demand Reduction Target (MW)	Electricity Consumption Reduction Target (TWh)
2010	2,700	Not Applicable	Not Applicable
2015	No Interim Target	4,550	13
2020	No Interim Target	5,840	21
2025	6,300	6,700	25
2030	Not Applicable	7,100	28

Source: Government of Ontario, *Ontario's Long-Term Energy Plan, Building Our Clean Energy Future.*

The LTEP also contains revised targets for installation of renewable generation capacity; these are shown in Table 2. The LTEP establishes a renewable generation target of 10,700 MW to be achieved by 2018. This includes renewables other than hydroelectric generation (i.e., wind, solar and bio-energy). Renewable targets that were contained in the IPSP-2007, which included hydroelectric generation, are also shown for reference but are no longer valid. As Table 2 shows, the new renewables target is more aggressive and reflects the large uptake of the Feed-in Tariff (FIT) program.

Table 2: Renewables Capacity Targets

Year	IPSP-2007 *	LTEP
2010	10,400 MW Refers to all renewables including hydroelectric. Adds 2,700 MW to the existing 2003 capacity of 7,700 MW.	Not Applicable
2018	Not Applicable	10,700 MW Refers only to 10,700 MW of wind, solar and bio-energy. Hydroelectric generation is counted separately, i.e., 9,000 MW hydro target – 19,700 MW in total.
2025	15,700 MW	Not Applicable

Note: *Unlike the LTEP target, the IPSP-2007 targets included hydroelectric generation.[21]
Source: Government of Ontario, *Ontario's Long-Term Energy Plan, Building Our Clean Energy Future.*

3.5 The New Framework for Conservation and Renewable Generation

LTEP Targets

Figure 1 shows several targets that previously governed electricity as well as new targets that have been put in place. The targets apply to different periods and are measured in different ways. The key target amounts established by the LTEP and set out in the Supply Mix Directive are shown in the green portion on the right of the diagram. All of these targets are annual savings targets that refer to the amount to be saved in the target year (i.e., 2015, 2020, 2025, and 2030) relative to a baseline year of 2005.

Progress towards meeting the LTEP targets is measured by counting the cumulative amounts of conservation savings that have persisted (are still delivering savings) from 2005 to the target year. The targets are based on an updated forecast of conservation potential that was originally completed for the IPSP-2007. The Supply Mix Directive instructs the OPA to exceed and accelerate achievement of the targets, if feasible and cost-effective.

These targets will be incorporated as the targets contained in the IPSP-2011. The LTEP states that 50 per cent of the 2030 conservation target will be achieved in the commercial sector, 30 per cent in the residential sector, and 20 per cent will come from the industrial sector. According to the Ministry of Energy, this allocation of the 2030 target is based on an OPA analysis conducted for the IPSP-2007, and should only be considered a rough estimate based on the potential for further savings in each sector.[22]

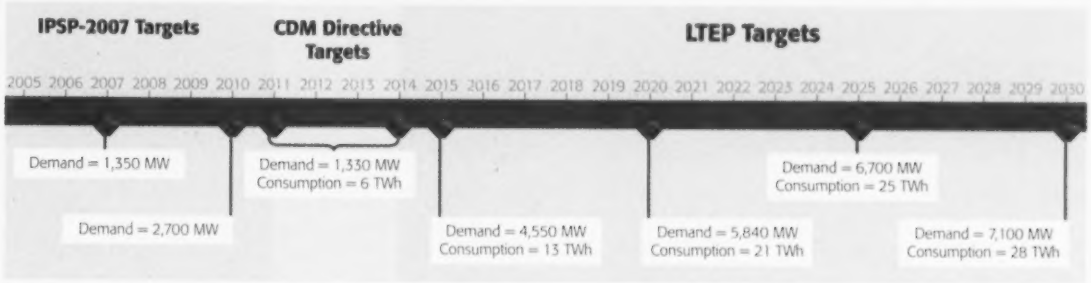

IPSP-2007 Targets
CDM Directive Targets
LTEP Targets
2005 2006 2007 2008 2009 2010 2011 2012 2013 2014 2015 2016 2017 2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030
Demand = 1,350 MW
Demand = 2,700 MW
Demand = 1,330 MW
Consumption = 6 TWh
Demand = 4,550 MW
Consumption = 13 TWh
Demand = 5,840 MW
Consumption = 21 TWh
Demand = 6,700 MW
Consumption = 25 TWh
Demand = 7,100 MW
Consumption = 28 TWh

Figure 1: Electricity Conservation Targets – LTEP, CDM Directive and IPSP

Source: Government of Ontario, *Ontario's Long-Term Energy Plan, Building Our Clean Energy Future.*

CDM Directive Targets

Shown in the orange area of Figure 1 are another set of conservation targets established on March 31, 2010, before the LTEP was issued. These targets were set out in a directive from the Minister of Energy to the OEB known as the "CDM Directive". On November 12, 2010, the Board issued a decision and order that allocated each LDC a share of the total province-wide target contained in the CDM Directive. Achievement of these targets is a condition of LDC licences.[23] Actions taken to meet the CDM Directive targets, depending on the persistence of the actions, are included in the contribution toward meeting the LTEP targets and will be incorporated by government when verifying progress on the LTEP targets.

Although conservation savings achieved for the CDM Directive's target can be counted toward achievement of the targets contained in the LTEP, progress on meeting the targets contained in the CDM Directive will also be measured separately from the LTEP targets on a stand-alone basis. The ECO notes two concerns with the stand-alone measurement. First, it is not clear how peak demand is defined for the peak reduction target. Second, the methodology for measuring the consumption target appears to be different from the way that LTEP consumption targets are measured. Clarity of definitions and measurement methodology is needed as there are several ways to interpret these.

The LTEP sets both the peak reduction and consumption targets as, respectively, a MW and TWh amount *achieved within each target year* measured from the 2005 baseline.

In the CDM Directive, the peak reduction target amount will be measured in the same way that the LTEP counts savings – as a MW amount *achieved in 2014*, at the end of the four-year period of 2011-14. It is not clear to the ECO how peak is defined.[24]

The consumption target contained in the CDM Directive will be measured as the TWh amount of *reduced electricity consumption accumulated over the four-year period, 2011-14*. This could be interpreted to mean counting the TWh amount saved in 2014 that results from programs implemented from 2011 to 2014. Alternatively, it could mean counting any amounts saved at any time (in 2011, 2012, 2013 and 2014) during the four-year period. The first interpretation is a more aggressive and demanding way to set the target. The second interpretation would be an easier target amount to achieve, and is a less demanding way to set the target.

The ECO recommends that the Ministry of Energy clarify how the peak demand and consumption targets contained in the Long-Term Energy Plan and Conservation and Demand Management Directive are measured.

Pre-LTEP Targets

Figure 1 also shows (in the blue shaded area of the diagram) previous demand reduction targets for 2007 and 2010 that were, respectively, set by the government or contained in the 2006 Supply Mix Directive and incorporated into the IPSP-2007. Verified savings achieved for these pre-LTEP targets (the 2007 and 2010 targets) will also be incorporated for measuring progress to meet the LTEP targets. These pre-LTEP targets were measured from a baseline year of 2005. As Table 1 shows, the new peak demand reduction targets are slightly more aggressive: 6,700 MW versus 6,300 MW, when comparing the only target year (2025) common between the LTEP and IPSP-2007.

Renewable Generation Targets

Figure 2 shows several targets that previously governed and currently apply for adding renewable generation capacity. The target now governing acquisition of renewables is the LTEP target of 10,700 MW (shown in red). The other targets (shown in gold) are superseded. It is important to note that the targets are not comparable because they are not symmetrical. Neither the type of renewable generation nor the amount of existing versus new renewable capacity included in each target is similar.

Ontario's acquisition of renewable generation capacity is now governed by the FIT. The procurement amounts of generation sought and achieved by previous tenders and programs are shown in the diagram below the timeline.

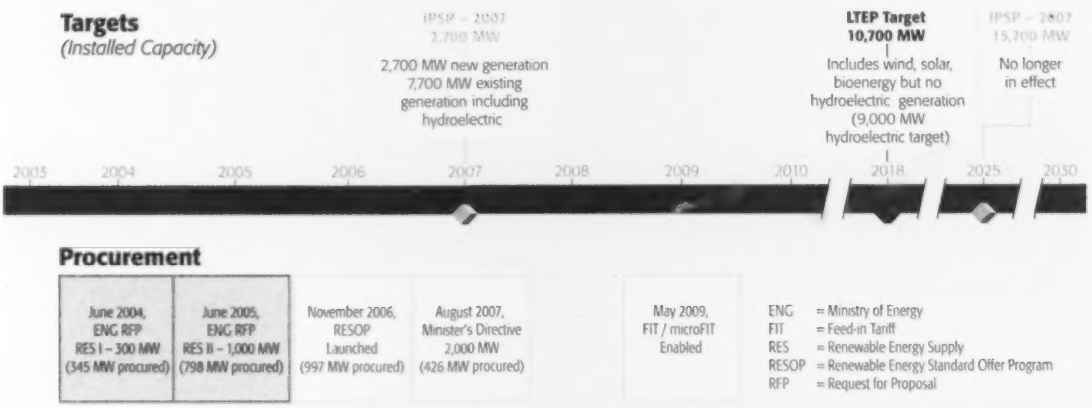


Figure 2: Renewable Generation Targets and Procurement

Source: Government of Ontario, *Ontario's Long-Term Energy Plan, Building Our Clean Energy Future*; OPA, *Integrated Power System Plan*; OPA, *A Progress Report on Electricity Supply – Second Quarter 2010.*

ECO Comment

General Comments

The LTEP is a far-reaching document, and the ECO commends the government for re-starting the IPSP process, as well as seeking public input on the LTEP's draft Supply Mix Directive through the Environmental Registry. The ECO's comments address the conservation and renewable generation features of the Plan, and do not focus on conventional generation or the load forecast that underpins the Plan, important as these are. The ECO comments on the LTEP from two perspectives: the LTEP as a system planning document for resource acquisition, and as a socio-economic policy with environmental impacts.

Before discussing these aspects, a generic comment is necessary as it touches on the overall credibility of the Plan. In the course of requesting information for this report, the ECO generally found the Ministry of Energy unwilling or unable to provide detailed explanations of elements of the Plan, particularly information underlying or supporting data presented in the LTEP.[25] The ECO questions the degree to which numbers related to conservation investment, ratepayer benefits from conservation, and claimed electricity savings were rigorously validated by the ministry. The ministry indicated that the LTEP was based on OPA-supplied data but did not provide source documents. Similarly, information sought on price forecasts in the Plan was deemed

confidential by the ministry and not supplied to the ECO. Some supply mix information – generation and conservation capacity – was provided after much delay, but there was insufficient time to analyze the data. Consequently, the ECO cannot comment on the accuracy of elements of the Plan or the validity of its propositions. This is an important limitation because the Supply Mix Directive is closely aligned with the LTEP, and the directive provides specific guidance for creating the IPSP. The IPSP-2011 must present these data so the assumptions can be scrutinized. Because of this limitation, the ECO tempers any statements of approval with this caveat.

The LTEP as an Integrated Resource Planning Document

Considering the LTEP as an operational plan – a technical guide for power system planning and program design – three aspects of the Plan are praiseworthy: (1) an expanded approach to setting conservation targets that includes both consumption and demand targets; (2) its explicit treatment of conservation as a supply resource; and (3) the impact of consumption targets in aligning CDM policy, planning, and programs. These three aspects are discussed in greater detail below.

First, it is commendable that it (and the Supply Mix and CDM directives) reflects an expanded approach to setting conservation targets that includes both consumption and demand targets. Our Annual Energy Conservation Progress Report – 2009 (Volume One) recommended such targets. In the ECO's view, it is self-evident that consumption-based targets are worthwhile because all supply technologies have negative environmental impacts, and conservation reduces the amount of new generation that would otherwise be built.

Consumption-based targets, like peak reduction targets, offer system planning benefits since both types of targets discipline the growth of generating capacity. The former reduces the need for baseload[26] and intermediate generators, and the latter reduces the need to add peaking generation. Forecasting demand with precision is difficult, and planners face the risk of overbuilding the electricity system. As an example, the IPSP-2007 proposed building 1,400 to 3,400 MW of additional new nuclear capacity and three additional natural gas plants.[27] Three years later, the LTEP has scaled this back to two new nuclear units (about 2,000 MW) and one gas-fired station because of lower than expected demand growth.[28]

Consumption targets, by reducing the need for new baseload plants and moderating the growth of the overall generation capacity, help keep the margin of error as low as possible. If excess capacity does develop, since the amount of generation built has been kept to a minimum and the size of the electricity system is smaller, the economic and environmental impacts of excess capacity will be less severe. Consumption targets offer additional environmental and economic benefits beyond what peak targets alone provide, since they reduce demand over the entire year, not only during periods of peak use.

The second praiseworthy aspect of the LTEP is its explicit treatment of conservation as a supply resource; tables and graphs in the LTEP show demand targets as "installed capacity."[29] The Plan states that conservation is the most cost-effective and calls it the first and best resource. This is a welcome addition that explicitly signals the philosophy underpinning electricity policy. The ECO questions, however, why the ministry did not extend this thinking to formally endorse a loading order. [30] Since the Supply Mix Directive instructs that targets should be accelerated or exceeded if possible, and the IPSP-2007 identified a "priority order" in which resources are planned (similar to planning proceeding on the basis of a loading order), clearer direction seems fitting. It should have been provided by embedding the principle of a loading order as a formal guiding principle in the Supply Mix Directive so that it is again used in the IPSP-2011.

A third positive feature of setting consumption targets is that it better aligns policy, planning and programs. The objectives and design of most CDM programs offered in Ontario are now reflected in the electricity plan. With the exception of industrial and residential demand response programs, all of Ontario's CDM programs are aimed at reducing consumption or improving efficiency; such programs target kilowatt-hour (kWh) savings. Putting consumption targets in place provides clarification of the government's priorities to LDC and OPA program managers, and ensures that the OPA and LDCs are encouraged to support these programs, instead of devoting resources largely to demand response programs.

The LTEP as a Policy Document

In the ECO's view, the LTEP does more than serve as the blueprint for the planning and design of the province's electricity infrastructure over the next two decades. In the ECO's opinion, the Plan is an important socio-economic policy statement that integrates energy, environmental and economic priorities. The Plan's proposals for more conservation, renewable energy and the smart grid are commendable. The Plan's major fault is that it is not an energy plan; rather, it is an electricity plan.

The Plan is an important socio-economic policy statement that integrates energy, environmental and economic priorities.

The Plan's foreword makes it clear that the LTEP serves a broader policy purpose closely tied to the *Green Energy and Green Economy Act, 2009* (*GEGEA*). The Plan links electricity infrastructure to an industrial strategy based on sunrise industries that manufacture clean energy technology. The LTEP also uses electricity planning to address climate change. It continues the environmental policy to decarbonize generation and shift Ontario away from coal-fired power, which has been deemed a sunset industry. It embraces the building of a smart grid. In doing so, the Plan promotes transformative technologies, that is, technologies used in innovative ways to create new business models and transform the electricity market. For example, it will accelerate utilities' evolution from wires companies simply delivering electrons to providers of energy services such as conservation and distributed generation.

The Plan also candidly acknowledges that prices will rise over 20 years because of capital investment in new infrastructure. The Plan attempted to engage Ontarians in a discussion of the need for higher electricity prices. Regrettably the government continued the policy approach of past decades: the only solution to higher electricity prices is lower electricity prices. By introducing rebates and tax credits to offset price increases, the government made little attempt to use the LTEP to frame the issue of rising prices as an opportunity to conserve, nor did it address the detrimental effect that rebates and other actions to shelter consumers from price signals have on load growth. Information should have been provided to help Ontarians understand that price subsidies work against conservation and some methods of lowering prices are better than others in maintaining conservation.

As a social policy document, the LTEP could have been improved by directly explaining the trade-offs that result from choosing *between* generation and conservation options and the trade-offs *among* generation options. The ministry's on-line consultation did provide a limited comparison of generation types, but not enough detailed information to understand the difficult choices raised by supply options. The Plan essentially evades these issues and missed an opportunity to use the LTEP to reach consensus. It should have devoted more effort to explaining that all supply options have negative environmental consequences and offer economic opportunities. It should have explained that public opposition – dissatisfaction with higher prices that reflect the true cost of power and local resistance to siting any type of generation – has frequently hindered reform of Ontario's electricity system. The Plan should have provided a tool for collective learning and acceptance of difficult choices by setting out a simple side-by-side comparison of the key trade-offs related to:

- Cost – compared on a common basis to allow equivalent comparisons between supply resources, including conservation;[31]
- Environmental impacts – description of unaccounted costs that are not included in the price of electricity (e.g., carbon and other emissions, waste management, plant decommissioning and site remediation, liability), and how these could be monetized;
- Technical constraints – operational limitations like transmission availability and grid operations;
- Public acceptance barriers – aesthetics, noise, health effects and safety; and,
- Economic development – the net potential jobs and spin-offs in traditional and strategic emerging industries.

In hindsight, considering the policy developments of 2011, the lack of guidance to electricity agencies, LDCs and the OEB on their mutual objective was a shortcoming of the LTEP. The Plan should have included a statement to counsel these organizations that their actions should reflect the common policy direction to achieve conservation. These organizations have a critical impact on determining the scope and pace of conservation, and the Plan should have set out the government's expectations of its agencies, distributors and the regulator.[32, 33]

Finally, the LTEP is an energy plan in name only. It discusses only electricity and essentially is an electricity plan. Primary energy sources such as natural gas, uranium and biomass are considered only in terms of providing thermal energy for electrical generation.[34] Discussion of renewable energy sources is similarly restricted to generation applications. Solar thermal and geothermal energy have other uses including space conditioning, domestic hot water and industrial processes (see Appendix A).

The Supply Mix Directive defines conservation to include geothermal heating and cooling and solar heating but, as befits an electricity plan, the definition applies only to load reduction from these technologies and not their ability to reduce the use of hydrocarbon energy sources. Similarly, the directive instructs the OPA to consider storage – its contribution to grid reliability, meeting peak demand, and providing customer and system benefits – but it restricts consideration to electrical storage to reduce power demand and does not include thermal storage to reduce the use of hydrocarbons.

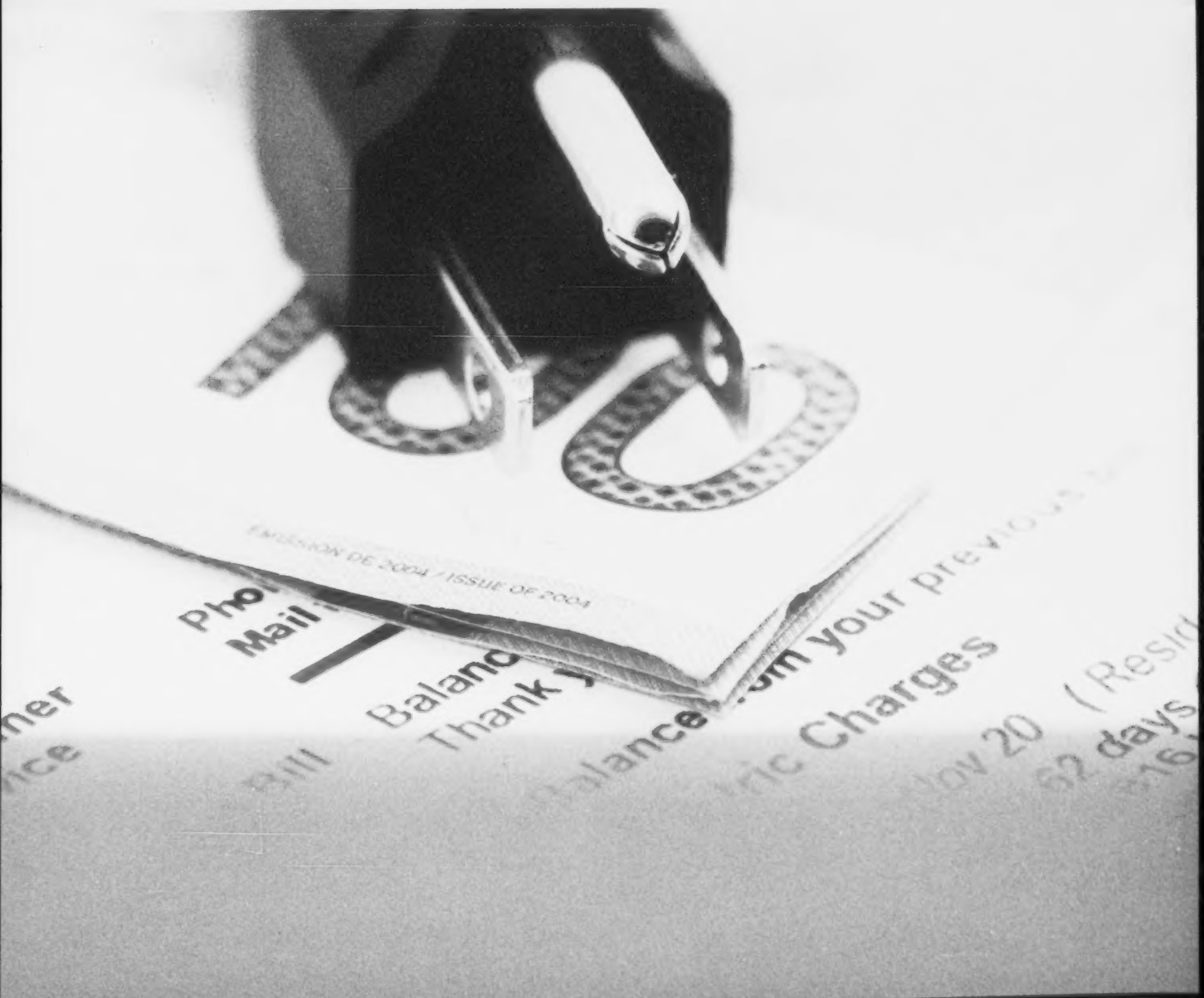
The consumption and conservation of oil, petroleum product transportation fuels, and propane receive not a single mention in the LTEP. A much needed policy discussion of applications for district energy, electrification of transportation, and the effect of cap-and-trade legislation on energy use is not included. These are serious shortcomings that should be addressed.

A plan is needed that would lay out a multi-fuel strategy linked to the inter-related activities of governments, electric and gas utilities, non-governmental organizations and businesses.[35] Some jurisdictions, such as California, integrate government and utility actions on multiple fuels to produce a multi-year energy action plan.[36] The need for a multi-fuel energy strategy is particularly important to guide policy for energy end uses that could be supplied by more than one fuel source. The LTEP encourages fuel switching for heating buildings away from electricity to natural gas, while the government's GHG reduction targets encourage fuel switching in the opposite direction.[37]

A starting point for producing a true energy plan, as recommended in the ECO's Annual Energy Conservation Progress Report – 2009 (Volume One), is to produce a comprehensive multi-fuel energy conservation strategy.

The ECO recommends that the Ministry of Energy build upon the work completed in the Long-Term Energy Plan and produce a comprehensive multi-fuel energy plan.

4: Electricity Pricing



The cost of electricity became front page news across Ontario in 2010. A combination of factors, including the roll-out of time-of-use (TOU) pricing, the application of the Harmonized Sales Tax (HST), and questions about the cost of new renewable power, raised concern about electricity prices among Ontario residents. The Ontario government was forced onto the defensive in explaining why and how much Ontario electricity prices will rise in the future.

The government's LTEP estimates that "all-in" electricity prices will rise by just over 30 per cent (in real terms) between 2010 and 2014. The government attributes these cost increases to investments in new renewable energy generation, transmission and distribution upgrades, and improvements to nuclear and gas capacity. After 2014, prices are expected to stabilize, with the bulk of investments in new capacity complete.

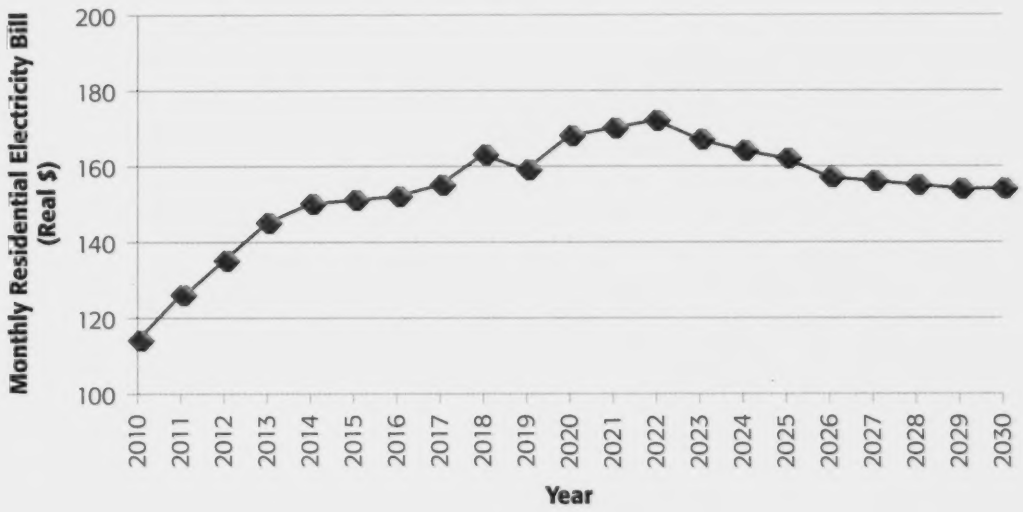


Figure 3: Projected Monthly Residential Electricity Bill, 2010 – 2030

Note: All-in, after-tax bill, assumes monthly consumption of 800 kWh.
Source: Government of Ontario, *Ontario's Long Term Energy Plan, Building Our Clean Energy Future.*

In Ontario, the government has significant power to influence the price of electricity. Levers of influence include government taxation and expenditures, and policy direction to the electricity agencies. The government must consider multiple policy objectives, which could include the following:

- Recovering the costs of operating the electricity system;
- Keeping pricing fair by ensuring that the electricity bill paid by each consumer (and each class of consumers) closely matches their share of the system costs (known as *cost causality*);
- Minimizing negative social and economic impacts, particularly for groups especially sensitive to price changes, such as low-income consumers and energy-intensive industries; and,
- Promoting other societal objectives, such as environmental protection, energy conservation, or job creation.

It is impossible to fully achieve all four objectives, and the government must make tough decisions when they come into conflict. Keeping in mind these levers of influence and the trade-offs that are made, the changes made to electricity pricing policy in Ontario in 2010 are discussed below.

4.1 Changing the Cost of Energy Through Fiscal Policy

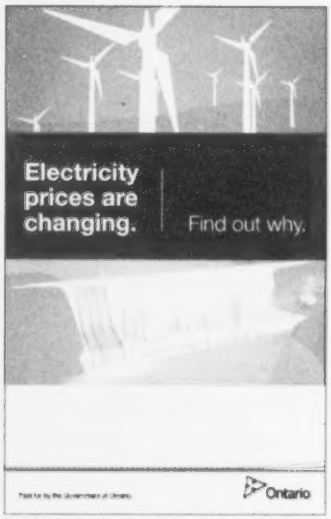
As part of the harmonization of the provincial sales tax with the federal Goods and Services Tax (GST), electricity (along with gasoline and home heating fuels) became subject to the 13 per cent HST beginning on July 1, 2010. Previously, these energy sources had only been subject to the 5 per cent GST. It is important to note that provincial taxation was a deliberate choice, not an inevitable consequence of harmonization, as the Ontario government instituted point-of-sale rebates for the provincial portion of the HST for several other categories of goods and services.

In the 2010 Ontario Budget, the government also announced two energy-related tax relief measures – the Northern Ontario Energy Credit ("to help with home energy costs, which are often higher in the north due to more severe winters"[38]), and the Ontario Energy and Property Tax Credit (to "help you with the sales tax you pay on energy"[39]). However, these credits are not directly tied to the amount of energy that a household consumes. Rather, they are income-adjusted credits that provide general tax relief for northern residents and low- to middle-income householders that pay rent or property tax.

With these two tax credits only six months old, the government introduced a third energy-related credit through 2010's Fall Economic Statement: the Ontario Clean Energy Benefit (OCEB). The stated purpose of the OCEB is to serve as a transitional measure to help Ontarians deal with the increased costs of investments in the electricity system. Unlike the two other tax credits, the OCEB rises in direct proportion to actual electricity consumption. Eligible consumers (residential, farm, small business, and other small consumers) receive a 10 per cent rebate off their after-tax all-in electricity bill. The OCEB is proposed to be in effect for five years. In 2011, the financial impact of the OCEB will be to transfer $1.1 billion from Ontario taxpayers to electricity ratepayers.

ECO Comment

The actions on energy pricing in 2010 show a government being pulled in several directions.



The historical argument for not taxing electricity was that it is a "necessity of life" and that taxation of such basic necessities is unfair to low-income individuals. By adding the HST to energy bills, while introducing tax credits that reduce or eliminate the income impact for low- and middle-income individuals, the government is now treating electricity like other goods and services and sending a more accurate price signal to all consumers about its cost, while maintaining the progressive nature of the tax system. The ECO believes this is a positive change that will further conservation.

On the other hand, the OCEB essentially reverses the impact of the HST and restores an artificial price subsidy on electricity. Since the rebate is funded from government revenue and the size of the rebate is proportional to the amount of electricity consumed, it uses the tax system to indirectly transfer wealth from low-volume energy consumers to higher volume consumers. There are other approaches that the government could consider if it believes that transitional assistance is necessary. The amount of the on-bill rebate could be a fixed amount,[40] instead of being tied to electricity consumption levels. Alternatively, the subsidy could be used to reduce the price of energy only in off-peak hours, creating a larger price differential between peak and off-peak prices and encouraging customers to shift their consumption to the off-peak period (see section 4.2 for more discussion of time-of-use pricing). The subsidy could perhaps also be reduced over the five-year period to transition consumer behaviour back to the need to conserve energy.

Subsidizing the price of electricity is a perverse incentive that undermines conservation. As with most goods or services, the price of electricity is inversely related to the amount that will be consumed. According to one estimate, the artificial 10 per cent reduction in electricity price provided by the OCEB could have the near-term impact of increasing total electricity consumption in Ontario by 1.3 per cent. This amount is equal to one-third of the electricity that is expected to be saved through utility conservation programs between 2011 and 2014.[41]

In the near term, consumers respond to price increases by reducing discretionary consumption through behavioural actions (e.g., turning the lights off, using less air conditioning). Options for action are limited and consumers may simply have to endure higher prices. However, over time, people also adapt through technological change and investment in conservation measures. The payback period for a house retrofit or an energy-efficient appliance becomes more attractive in light of higher energy prices. This means that the long-term conservation response to price changes is much greater than in the short term. A 10 per cent rise in residential prices could lead, over the long-term, to a 9 per cent drop in consumption.[42] The OCEB reduces this impact and hinders investment in conservation.

The ECO recommends that the Ministries of Energy, Revenue, and Finance improve the design of the Ontario Clean Energy Benefit so that any transitional assistance on electricity bills does not act as a disincentive to conservation.

4.2 Variable Pricing

As is well known, Ontario is moving towards variable electricity pricing. In 2010, regulatory changes were made that increased the time-sensitivity of electricity prices for large electricity consumers. Changes have also been considered for smaller consumers, even though time-of-use pricing is still in the process of being rolled out for this group.

Understanding Electricity Supply Costs

To assess the impact of variable pricing, it is necessary to understand how electricity supply costs, which do not include transmission and distribution costs, are recovered through prices for large and small customers.

Electricity supply costs are composed of:

- Costs payable to electricity suppliers (generators, importers, and demand-side resources) through the wholesale electricity market; and,
- Additional contract costs payable to suppliers through the Global Adjustment.

The wholesale market price closely follows the *variable* cost of electricity production. It is low when nuclear or baseload hydroelectric are able to supply all demand, rises to track the cost of fuel when coal or gas plants are needed, and rises even higher when options such as peaking gas and hydroelectric or demand response (consumers being compensated to reduce their electricity consumption) are called on.

4.2.1 Varieties of Variable Pricing

Variable pricing includes several different pricing schemes. All of these differ from fixed pricing, where the charge per unit of electricity consumed remains the same at all times.

- **Time-of-use (TOU) pricing** sets different electricity price levels (on-peak, mid-peak and off-peak, for low-volume consumers in Ontario) for different hours of the day. The hours at which a given price will be in effect are known in advance, and periodic reviews of the price levels are undertaken to adjust prices as needed to ensure cost recovery.
- **Real-time pricing** varies on an hour-to-hour basis in an unpredictable fashion. The price in a given hour is determined "on the spot" in a wholesale market and is not typically known far in advance.
- **Critical peak pricing** applies very high prices for a few hours in the year when the electricity system is under extreme stress (typically hours of seasonal peak demand). These hours may or may not be announced in advance.

Unfortunately, the wholesale market in Ontario has proven inadequate for new generators to recover their fixed capital costs. To ensure that investments in new and refurbished generation are viable, almost all electricity generators (including most gas, renewables, and nuclear) are provided support payments through the Global Adjustment. Without this assistance, it is unlikely that sufficient supply would be provided by the market to meet Ontario demand. In recent years, many new generators with long-term contracts have come on-line, and the percentage of the supply cost that is due to the Global Adjustment has risen dramatically while the wholesale market price has simultaneously fallen. Funding for electricity conservation programs also comes from the Global Adjustment.

Figure 4: Wholesale Electricity Price and Global Adjustment in Ontario, 2005 - 2010

Source: Independent Electricity System Operator.

All Ontario electricity consumers pay the Global Adjustment. However, for small-volume customers on the Regulated Price Plan (RPP), which includes virtually all residential customers and some small businesses and institutions, the Global Adjustment charge is bundled inside the regulated rate determined by the OEB, and does not appear on bills as a separate line charge.

Under TOU pricing, the cost of electricity as determined from both the wholesale market and the Global Adjustment is split into three buckets – off-peak, mid-peak and on-peak. The share of costs that is assigned to each bucket determines the three TOU prices. It is a straightforward calculation to assign the appropriate portion of the wholesale market costs to each bucket, but judgements need to be made about how to assign the Global Adjustment costs. For example, support payments for nuclear, baseload hydro, and energy efficiency are assigned equally across all periods. Support payments for gas generators are assigned based on the proportion of time that the plants run, and support payments for demand response programs are assigned only to on-peak hours.[43] Changing the way these costs are allocated would change the TOU prices.

Large-volume electricity consumers, such as manufacturers, schools, and hospitals, are not billed on the basis of rates set under the RPP. They are exposed to the wholesale electricity market and pay a real-time market price that changes hourly or even more frequently, and a Global Adjustment charge that (until 2011) was fixed in proportion to their total electricity consumption.

Critical Peak Pricing for the Global Adjustment

In October 2010, the government amended O. Reg. 429/04, made under the *Electricity Act, 1998*, changing the way that the Global Adjustment would be calculated. Under the new rules, customers are divided into two groups.

- Very large consumers (e.g., major industrial facilities, universities) with an average monthly peak demand of more than 5 MW are defined as Class A consumers. These consumers will be billed a Global Adjustment charge that is proportional to their share of provincial electricity consumption during the five highest hours of Ontario demand in the entire year.[44]
- Smaller consumers are defined as Class B consumers and will continue to be billed the Global Adjustment on a volumetric basis, that is, a Global Adjustment amount is applied according to the total amount of electricity consumed.

This change essentially acts as a form of critical peak pricing. It provides a powerful incentive for Class A consumers to reduce their consumption during periods of system peak, by assigning roughly 50 per cent of their yearly electricity commodity cost based on their consumption during only a few peak hours of the year.

Crucially, the exact hours of yearly system peak are not known in advance because demand will vary with factors like weather and economic activity. This will likely lead Class A consumers to reduce their consumption during a larger number of hours (perhaps 50 to 100 hours), in order to be assured of lower consumption during the critical five hours. The Independent Electricity System Operator (IESO) estimates that the change brought in by the amendment to O. Reg. 429/04 could reduce Ontario peak demand by 450 to 500 MW, potentially avoiding some $450 million in capital costs for new facilities, and reducing the average electricity supply price (Global Adjustment plus wholesale price) by about 0.4 cents per kWh.[45]

The price paid by smaller consumers will be indirectly impacted. Prior to this regulatory change, Class A consumers had a much higher percentage of their electricity consumption in off-peak hours than did smaller consumers, as many Class As are large industrial firms that run 24 hours a day. In January 2011, Class A consumers accounted for 15 per cent of total Ontario electricity consumption, but only 11 per cent of peak demand for the corresponding base period.[46] Under the old rules, Class A consumers would have paid 15 per cent of the Global Adjustment costs, under the new rules they will pay 11 per cent. Over the course of a year, this represents a shift of electricity costs of approximately $150 million from Class A consumers to smaller Class B consumers.[47] This amount could increase if Class A consumers act as expected and find ways to reduce their consumption during peak hours.

Time-of-Use Prices for Small Consumers: Reviewing the Price Spread

At the end of 2010, more than 1.6 million small Ontario consumers billed under the RPP were now paying TOU prices for their electricity, as several large distributors, like Toronto Hydro, had converted the bulk of their customer base to TOU pricing.

With TOU pricing just coming into effect for most RPP consumers, the government passed a regulation[48] that requires the daily off-peak price period to begin no later than 7:00 p.m., starting May 1, 2011 (the off-peak period had previously started at 9 p.m. on weekdays). At the same time, the OEB began a review of the price structure of time-of-use prices.

The ECO has previously noted that the price differential between on-peak and off-peak prices for RPP customers may be insufficient to lead to significant load shifting. A study conducted as part of the OEB review reached a similar conclusion

The ECO has previously noted that the price differential between on-peak and off-peak prices for RPP customers may be insufficient to lead to significant load shifting.[49] A study conducted as part of the OEB review reached a similar conclusion, estimating that the then-current peak price/off-peak price ratio of 1.9:1 (9.9 cents per kWh during peak periods, compared to 5.1 cents per kWh during off-peak periods) could deliver approximately a 1 per cent drop in the average consumer's peak demand. According to the study, a greater peak/off-peak ratio of 4:1 could potentially deliver three times as great a drop in peak demand.[50]

The study also suggested several options that would increase the peak/off-peak price ratio. However, following stakeholder consultation, the OEB noted in March 2011 that there was little support from stakeholders for any of these options, particularly as they would deviate from cost causality. The OEB concluded that it would be premature to make any changes to the TOU pricing structure at this time, and also announced that it would initiate a data collection process on customer response to TOU pricing, which could be used to support further analysis of the TOU pricing structure in the future.[51]

ECO Comment on Variable Pricing

In light of Ontario's proposed supply mix for the next twenty years (see section 3), two goals appear desirable for variable electricity pricing: price should reflect the real-time marginal cost of power; and price should send a signal to avoid extreme price events. These are discussed below.

1. Prices should reflect the real-time marginal cost of power. The marginal cost of power reflects the balance between supply and demand and has predictable and unpredictable components. The daily rise and fall in electricity demand is predictable and can be well-approximated with TOU pricing. Generator outages and varying supply from intermittent renewable electricity sources (wind and solar) add an unpredictable element. This will become more important in the future, as the percentage of intermittent sources in Ontario's supply mix will increase dramatically. Only real-time pricing can respond to this unpredictability.

   Prices should reflect the real-time marginal cost of power.

   Therefore, the ECO suggests that Ontario conservation programs should provide opportunities for RPP consumers to respond to real-time price signals. This could take several forms. For example, a voluntary opt-in program could pass through real-time prices to customers willing and able to respond to price variation (e.g., customers with smart appliances, consumption monitors). Another approach is to link the activation of programs such as *peaksaver*® (a residential load control program) directly to price signals from the wholesale market. Currently, utilities activate this program by reducing the energy use of consumer appliances at times of high system demand, but it is not directly based on real-time prices.

2. Prices should send a signal to avoid extreme peak events. Ontario's electricity system is sized to meet the highest demand of the year. Reducing this seasonal peak may deliver significant cost savings by eliminating the need for new power plants or transmission lines. Crucially, because these are future costs that may be avoided, they are not fully accounted for in any price signal that is based only on recovering existing system costs. For this reason, the ECO believes that the peak-to-off-peak price differential for TOU rates for RPP customers should be raised in order to reduce peak demand and avoid these future costs, even if this deviates from cost causality. However, the OEB's reluctance to tinker with the TOU structure at this time is understandable for two reasons: consumers are still becoming familiar with the time periods and prices for TOU pricing; and, the Ontario-specific evidence as to how TOU pricing affects consumer behaviour is still very preliminary.[52]

   Prices should send a signal to avoid extreme peak events.

ECO Comment on Critical Peak Pricing

With the Global Adjustment regulation, the government has clearly broken from cost causality in order to provide a strong incentive to reduce peak demand. The ECO supports this approach and notes the economic and environmental benefits that will result from making more efficient use of our existing generation options and reducing the need for capital investments in new infrastructure.

However, the ECO has two minor concerns, both of which relate to the transfer of electricity costs away from large industrial consumers and onto other consumers. The first concern is the limitation of critical peak pricing to customers with a load greater than 5 MW. This deprives smaller customers of the ability to reduce their Global Adjustment costs by reducing peak demand. The second concern is that the Global Adjustment includes many support costs that are unrelated to peak demand, such as payments for nuclear generation. Charging 100 per cent of these costs on the basis of a consumer's peak consumption may be unfair to customers with peaky loads (e.g., commercial building owners).

The first criticism can be addressed by expanding critical peak pricing for the Global Adjustment to more customers. The Ministry of Energy advised the ECO that it intends to evaluate the merits of expanding coverage to a wider group of electricity consumers within 12 months,[53] an action that the ECO supports.

However, even with a larger group of customers subject to critical peak pricing, the criticism that the regulation is unfair to customers with peaky loads would remain. The ECO suggests that a more balanced approach might be to assign some percentage of Global Adjustment costs based on critical peak pricing and some percentage based on volumetric consumption. This may still provide sufficient incentives for peak reduction, while being fairer to consumers in terms of recovering existing system costs.

4.3 Taking Ownership of Electricity Bills: Suite Metering in Multi-Unit Residential Buildings

Bill 235, *An Act to enact the Energy Consumer Protection Act, 2010 and to amend other Acts*, received Royal Assent in May 2010. While the main focus of Bill 235 was to enhance consumer protection requirements with regard to energy retailers, it also contained provisions relevant to energy conservation that dealt with suite metering in multi-unit residential buildings. In addition to enacting the *Energy Consumer Protection Act, 2010* (*ECPA*), the bill amended several other statutes, including the *Residential Tenancies Act, 2006* (*RTA*).

Suite metering involves billing consumers in multi-unit buildings based on the specific electricity consumption of each unit. It includes **unit smart metering,** where the LDC installs an individual smart meter for each unit, and **sub-metering,** where the LDC installs only a bulk meter for the building, and a private company installs and operates an individual meter for each unit and handles the billing of individual consumers. LDCs are subject to a greater degree of oversight by the OEB than sub-metering providers are. However, the rules under the *ECPA* and the *RTA* regarding the installation and use of suite meters for individual billing are essentially the same for both groups.

The multi-unit residential sector is large, with approximately 1.7 million units in Ontario, 87 per cent of which are rental units, including social housing and subsidized units. It is estimated that only about 16 per cent of rental units are individually metered for their electricity consumption.[54]

At first glance, suite metering would appear to be a sure win for energy conservation. Residents who are responsible for paying their own electricity costs will certainly exercise more discretion in how they use energy. The energy conservers in a building will no longer be subsidizing the energy hogs. The reality is somewhat more complex. Suite metering has led to heated debate and raised consumer protection issues, particularly for existing rental buildings. On one side, the sub-metering industry and landlords have argued that tenants are in the best position to reduce their energy consumption, and individual billing for electricity through suite metering is the incentive needed to drive this change. On the other hand, tenant and poverty reduction advocates have suggested that landlords are actually in the best position to reduce energy consumption, through efficiency improvements to the building envelope and to the major appliances that they provide to tenants. If suite metering is introduced, the incentive for landlords to make these improvements disappears. From this perspective, suite metering is appealing to landlords not due to its energy efficiency benefits, but because it removes a volatile cost from their books and passes it onto tenants.

The legislative authority for introducing suite metering into rental apartments, prior to enactment of the *ECPA*, was unclear,[55] but this lack of clarity did not prevent sub-metering companies from entering into agreements with landlords, installing sub-meters, and billing tenants. The OEB received a large number of complaints from sitting tenants concerning these sub-metering

installations. Some common complaints were that the corresponding rent reduction turned out to be far less than the new electricity bill, and that sub-metering providers were charging installation and administration fees. In 2009, the OEB ruled that these installations had been unauthorized and that any resulting contracts were unenforceable.[56]

The *ECPA* and the *RTA* amendments remove the confusion and provide a clear legal framework for suite metering, both for LDCs and sub-metering providers. Two subsequent regulations, O. Reg. 389/10 - General, made under the *ECPA*, and O. Reg. 394/10 – Suite Meters and Apportionment of Utility Costs, made under the *RTA*, have provided additional details.

The key elements of the new suite metering framework are as follows:

- Suite metering is mandatory for new residential buildings;
- Suite metering can only be undertaken in units in existing buildings with the consent of the tenant (for rental buildings) or the condominium corporation's board of directors (for condominiums);
- Suite metering in rental units includes the additional conditions:
    - Rent for sitting tenants must be reduced by an amount that accounts for the cost of electricity, based on a regulatory formula;
    - Refrigerators included as part of a rental unit must meet minimum efficiency standards (based on date - existing refrigerators must be 1994 model year or later, replacements must be 2002 model year or later);
    - Prior to seeking tenant consent for suite metering, the landlord must provide information on the expected rent reduction and the refrigerator's energy consumption;
    - Suite metering will not be permitted in rental units where electricity is used to heat the unit (unless the suite meter separately measures and bills for only the electricity not used for heating); and,
    - When a rental unit is vacated, the landlord is allowed to implement suite metering without consent, however, prospective tenants must be provided with information on the historic electricity consumption of the unit and the refrigerator's energy consumption.
- The OEB is given authority to regulate the rates of sub-metering providers, should this be necessary.

ECO Comment

There is no doubt that suite metering delivers results. A pilot project in Oakville showed a 22 per cent drop in average electricity consumption in a condominium building which switched from bulk metering to suite metering.[57] This is in line with results from New York State, where a range of case studies shows electricity savings from 10 to 20 per cent following the introduction of suite metering.[58]

Given that new buildings are subject to relatively strict building code and energy efficiency standards, the greatest remaining savings are likely to come from individual behaviour. For this reason, the ECO supports the government's decision to mandate suite metering in new buildings. However, this should be complemented by policies that support and encourage the highest degree of energy efficiency (substantially better than the Ontario Building Code) in the initial construction of new buildings. The requirement for landlords to provide information on the unit's historic electricity consumption to prospective tenants is a small step in this direction, as it means that the energy efficiency of the building unit becomes a piece of information that will affect the market rate.

The decision to make suite metering conditional on the consent of sitting tenants in existing buildings will certainly slow the roll-out of suite metering, as it may not make economic sense for landlords to convert to suite metering for a building unless the majority of tenants agree to participate. However, given the attendant consumer protection issues that arose prior to the enactment of the *ECPA*, this is probably a necessary compromise.

Suite metering of electric heating in rental units is prohibited by the *ECPA* regulation, because the amount of electricity used for heating these units is more influenced by the properties of the building envelope than tenant behaviour, and it is the landlord

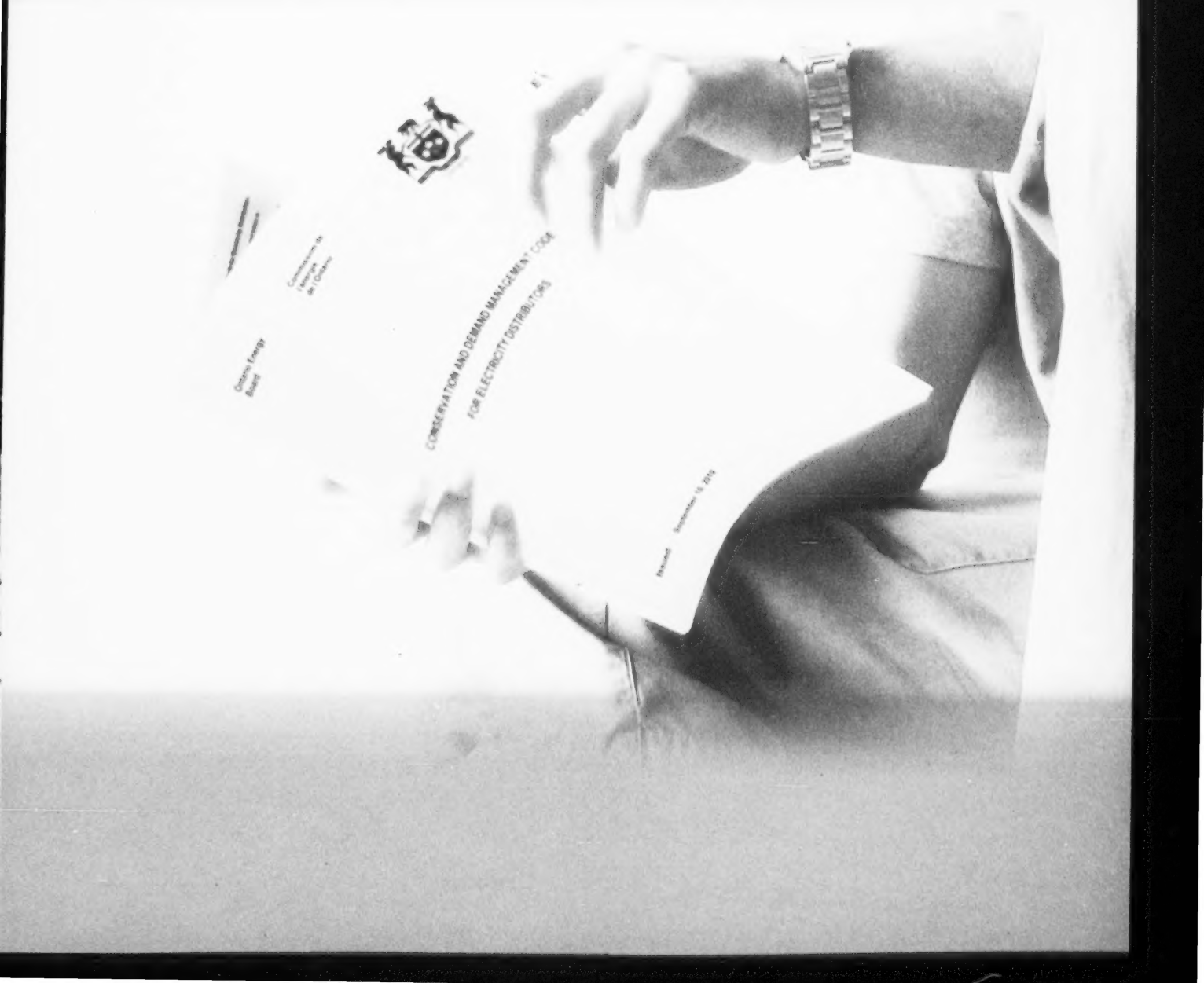
who can improve the envelope. The rationale for the regulatory requirement that refrigerators must achieve a certain energy efficiency level prior to allowing suite metering is similar – again, the efficiency of this equipment is not within the tenant's control. These are sensible decisions, although the ECO believes that an exception could potentially be made to allow suite metering in new electrically heated rental buildings, particularly for buildings that substantially exceed Ontario Building Code energy standards.

The ECO believes that the *ECPA* permits suite metering under the conditions where it will have the most benefit, while also ensuring adequate consumer protection for existing tenants. The ECO commends the ministries of Energy and Municipal Affairs and Housing for establishing a clear legal framework that will transition Ontarians towards increased responsibility for their electricity consumption.

4.4 Conclusion

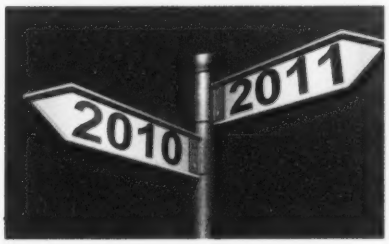
Overall, the ECO believes that Ontario is generally moving in the right direction with electricity pricing, with the qualifications noted above (in particular, concern regarding the current design of the OCEB). The roll-out and refinement of variable pricing and the clear rules for suite metering ensure that more Ontario consumers will receive price signals that better reflect the true cost of electricity, providing the proper incentives for energy conservation.

5: Conservation and Demand Management Code and Targets for Electricity Distributors



5.1 The Changing Roles and Responsibilities in Conservation and Demand Management

The state of flux in Ontario's electricity sector over the past 20 years has directly affected electricity conservation policy and the role LDCs play in CDM. The first serious efforts at province-wide CDM initiatives started in the mid-1980s. In an effort to delay the need for new generation, Ontario Hydro embarked on a large-scale CDM program. However, in the early 1990s, a recession hit and electricity demand dropped. As a result, Ontario Hydro's conservation programs were abandoned as priorities shifted towards constraining costs, especially for new resources.



In the late 1990s, the province was preparing for a competitive electricity market. With the *Energy Competition Act, 1998*, electric utilities became "wires only" companies. LDCs were restricted to distributing electricity, leaving CDM to the market as a response to market price. It was not until the passage of the *Electricity Restructuring Act, 2004* that LDCs were permitted to re-engage in CDM activities.

Over the last several years, conservation has resurfaced as a key part of the province's electricity plan, positioning LDCs to play a central role in CDM.

2005-2007: The Ontario Energy Board Framework

From 2005 to 2007, 85 LDCs designed and delivered CDM programs referred to as "third tranche" conservation programs. Distributors were granted increases in their 2005 rates if an equivalent amount was spent on CDM by the end of September 2007. Some distributors were granted extensions to continue programs into 2008. Under this framework, distributors prepared and submitted CDM plans and budgets for approval and provided regular reports on the progress of CDM programs to the OEB.

2007-2010: The Ontario Power Authority Framework

In 2007, the framework for CDM programs changed. The June 2006 Supply Mix Directive to the OPA required that conservation be a key component of the province's electricity plan. A month later, the Minister of Energy directed the OPA to co-ordinate and fund conservation programs for LDCs by establishing a three-year fund of up to $400 million. The directive was silent on the role of LDCs in CDM and their source of funding beyond 2010.

From 2007 to 2010, electricity distributors could either: contract with the OPA to deliver standard CDM programs; apply to the OPA for funding of custom programs; or apply to the OEB for CDM initiatives targeted at consumers within the distributor's service area. The process for OEB-approved programs remained the same, that is, CDM was funded through distribution rates and a performance incentive called the Shared Savings Mechanism continued to apply. This financial incentive allowed distributors to share 5 per cent of the net savings resulting from CDM programs they initiated. An additional source of funding was created for OPA programs and this operated independently of the OEB framework's funding. Funding was provided through the Global Adjustment, and the performance incentive was paid either per participant or per kW of savings achieved, depending on the program.

During this period, it was expected that LDCs would act primarily as delivery agents for the OPA's standard CDM programs. Only a few OEB-approved and OPA-funded LDC custom programs were offered.

2011-2014: Mandated LDC Delivery Framework

The *GEGEA* once again shifted the CDM framework in significant ways. The *GEGEA* allowed for LDCs to be given mandatory conservation targets as part of their licence condition. In the March 31, 2010 CDM Directive, the Minister of Energy specified the total province-wide reductions for both electricity consumption and peak demand that LDCs must achieve by 2014. The directive also required the OEB to allocate the province-wide targets among LDCs and to issue a Code with rules to govern how LDC targets are met. Unlike previous directives, the CDM Directive was prescriptive. The Minister laid out a list of specific rules the OEB must consider in developing the Code.

On April 23, 2010, the Minister directed the OPA to provide advice to the OEB on LDC CDM activities and targets, and also to design, deliver and fund OPA-Contracted Province-Wide programs.

Distributors must meet their CDM targets by delivering either: unique CDM programs approved by the OEB (referred to as Board-Approved Programs); province-wide CDM programs designed by the OPA (referred to as OPA-Contracted Province-Wide Programs); or a combination of the two. The CDM framework allows for Board-Approved Programs to be designed by individual LDCs or co-operatively between multiple LDCs. In keeping with the Minister's directive, all CDM programs must start on January 1, 2011 and end on December 31, 2014.

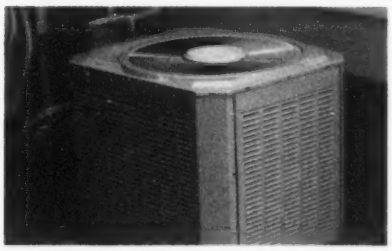
The 2011 to 2014 framework adopts elements from previous frameworks. Oversight of some CDM activities has been shifted back to the OEB, as was the case in the 2005 to 2007 period. A significant difference from the previous framework is that there is now a single funding approach. In the 2007 to 2010 framework, funding and performance incentives differed according to the approving agency (i.e., the OPA or OEB). Under the mandated LDC delivery framework, all CDM programs are now funded through the Global Adjustment, and the performance incentive is based on the amount of kWh and kilowatt (kW) savings achieved within a distributor's service territory, regardless of whether those savings result from province-wide programs or custom programs. In this sense, given that it is a licence condition, responsibility for conservation success lies with each individual LDC.

5.2 The New Conservation and Demand Management Framework

The OEB released the final CDM Code on September 16, 2010 and issued its Decision and Order for CDM targets on November 12, 2010. LDCs have been ordered, as a condition of their licences, to meet their CDM targets and comply with the CDM Code.

5.2.1 Conservation and Demand Management Targets

For the first time, CDM is a mandatory function for electric utilities. In accordance with the Minister's directive, the OEB allocated CDM targets for each LDC to achieve a total provincial savings of 1,330 MW of peak demand in 2014 and 6,000 gigawatt-hours (6 TWh) of electricity consumption over the four-year period. Savings from CDM initiatives implemented prior to 2011 or persisting after 2014 will not count toward the utilities' target. Currently, it is unclear what type of action will be taken by the OEB if an LDC does not meet its CDM targets.



With advice from the OPA, the OEB assigned individual LDC targets based on 2008 and 2009 data. Energy savings targets were allocated according to each distributor's share of total energy consumption by customer account type. Peak demand savings targets were based on each distributor's average contribution to the top ten system peak hours.

The intention of the peak demand targets was to reduce province-wide peak demand. Beginning 11 years ago, Ontario's system peak demand has occurred in the summer. This is mainly due to air conditioning load in the Greater Golden Horseshoe region. As a result, distributors' peak reduction targets and the OPA's demand response programs were developed primarily to address summer system peak. Peak demand on many LDCs' distribution systems, however, occurs in winter. Accordingly these LDCs may wish to design programs that address winter peak demand. LDCs are not prohibited from designing programs that address winter peaks. When assessing demand savings from a specific conservation program, LDCs can choose to apply either winter peak savings or summer peak savings from a given conservation program towards their peak demand savings target.

5.2.2 Conservation and Demand Management Code

The CDM Code sets out the obligations and requirements which distributors must comply with in order to achieve their CDM targets, including: rules related to reporting requirements; Board-Approved Programs; and, performance incentives. Each of these requirements is discussed below.

Reporting Requirements

All electricity distributors were required to submit a CDM strategy by November 1, 2010. Each distributor's strategy outlined its four-year plan to meet its CDM targets, including annual milestones for meeting its targets, descriptions of all the CDM programs to be offered, confirmation that CDM programs will be offered to all customer types, and details as to how administrative efficiencies and co-ordination with other agencies will be pursued.

Distributors must also file an annual report to the OEB by September 30 of each year, and provide an overall review of the activities undertaken to achieve their CDM targets in the previous calendar year. Annual reports must include program descriptions, participation levels, funds spent, evaluation results based on the OPA's Evaluation, Measurement and Verification (EM&V) Protocols and progress towards CDM targets.

Board-Approved CDM Programs

The CDM Code sets out the specific requirements that the distributor must include in its application for Board-Approved Programs (BAPs), including program details, expected results and the projected annual budget. The CDM Code also sets out specific requirements regarding cost-benefit analysis and program evaluations.

BAPs must be cost effective as determined using the OPA's cost-effectiveness tests, and must use the OPA's Measures and Assumptions Lists or provide justification if varying from these lists. There are three exemptions from the cost-effectiveness requirement: pilot CDM programs; educational CDM programs; and, low-income CDM programs.

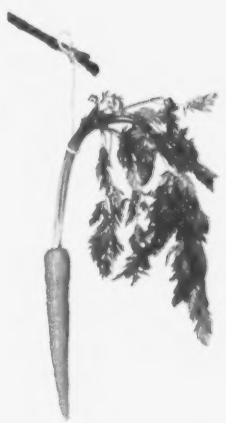
Unlike the natural gas conservation framework, which has a maximum conservation budget (see section 6), there are no spending restrictions for electricity CDM programs aside from ensuring programs are cost-effective. LDCs are not restricted to a spending limit for conservation programs or in the number of BAPs permitted. However, when approving CDM programs, the OEB will assess the reasonableness of the budgets requested and take into consideration the number of pilot and educational CDM programs an LDC already has or plans to undertake. If an LDC wishes to redirect funds once BAPs have been approved, the LDC must apply to the OEB to re-allocate funds that exceed 30 per cent of an approved budget for an individual CDM program.

With the CDM Code, the EM&V process is stricter than in the past. For each BAP application, distributors must file a program evaluation report that is based on the OPA's EM&V Protocols. Results from the BAPs must also be evaluated using the same protocol by an independent third-party evaluator selected from the OPA's vendor of records list. The LDC must file the third-party reviewer's report with each annual report. The report will also be used, along with the LDC's report, in verifying results for performance incentives. The OPA will remain responsible for the EM&V of OPA programs, and the results will be shared with the LDCs for inclusion in their annual reports.

The CDM Code also specifies what will not qualify as a BAP. These include programs that duplicate an OPA program, are related to infrastructure (new or existing), or are programs associated with the OPA's FIT or microFIT Program.

Performance Incentives

The CDM Code provides for a single performance incentive mechanism for both OPA programs and BAPs. In accordance with the Minister's directive, the Code sets out a mechanism for a tiered performance incentive for distributors meeting 80 per cent of each CDM target, up to 150 per cent of each CDM target. A distributor can begin receiving incentives once it has reached 80 per cent of both its peak demand reduction and electricity savings targets.



The new incentive structure provides a specific dollar amount per kW and kWh of savings achieved, with the dollar value increasing in tiers relative to the distributor's results against its targets. A total of $72 million over the four-year period will be available for performance incentives, accounting for approximately 5 per cent of the total net income for all distributors.

For programs where several entities participate in the delivery of a program, a distributor can only claim the performance incentive relative to its contribution to the CDM program. For BAPs, an LDC must demonstrate it was central to the CDM program to receive full attribution of those savings. Centrality is established if an LDC's budgetary contribution is greater than 50 per cent of the total program cost or if the distributor can prove that it initiated the partnership, program or implementation of the program. If a distributor does not meet the test for centrality, it can submit a proposal for attribution and the OEB will decide whether the proposal is acceptable.

5.2.3 OPA-Contracted Province-Wide Programs

As directed by the Minister in April 2010, the OPA developed province-wide CDM programs for residential, business (commercial and institutional) and industrial customers to be offered from 2011 to 2014. With the exception of a few new initiatives, the majority of OPA programs are enhancements of programs offered in the past. On July 5, 2010, the Minister also directed the OPA to develop province-wide CDM programs targeted specifically at low-income consumers as part of its suite of province-wide CDM programs (see section 5.2.3.1).

OPA-Contracted Province-Wide programs have been slow to roll out in the market. LDCs must contract with the OPA to be delivery agents for province-wide programs in their distribution areas. The contract, known as the Master Agreement, was not available for LDCs to review until late January 2011.[59] The specific details of CDM programs are laid out in Program Schedules as attachments to the agreement. At the end of January 2011, only the residential and business programs were available for LDCs to review. The OPA began delivery of the residential CDM programs on behalf of LDCs to ensure programs were launched by January 1, 2011, but the business programs did not launch until early March.[60] The program schedule for the industrial program was released in March 2011 and the schedule for the low-income program was released on May 9, 2011. As a result, those programs are unlikely to launch until almost halfway through the year.

Although some LDCs may choose to rely entirely on province-wide programs to meet their individual targets, some BAPs will still be necessary to achieve the provincial targets. The OPA forecasts its province-wide programs will achieve approximately 80 per cent of the LDCs' aggregate CDM targets.[61] Almost half of the savings are expected to come from the business sector (commercial and institutional), approximately one-third from the residential CDM programs (including low-income), and the industrial programs are expected to provide the remainder.

5.2.3.1 A Province-Wide Low-Income Program

In Ontario, approximately 16 per cent of households are low-income, and they often occupy older, less energy efficient homes with older appliances. While financial assistance programs are important for helping with energy bills in the short term, providing Conservation and Demand Management (CDM) initiatives targeted at low-income households can have a greater impact by reducing energy bills on a sustained basis.

Offering CDM programs targeted at low-income consumers can also help to redistribute the burden and benefits of CDM initiatives. Ratepayer funded conservation programs can result in low-income consumers paying their share of the costs (through their utility bills) but not receiving their share of the benefits. Although low-income consumers are eligible for conservation programs offered, they often face significant barriers that do not allow them to participate. Most CDM programs require that the household pay a portion of the costs, which low-income households typically cannot afford. Furthermore, for low-income renters the cost savings incentive is split between landlords and tenants. As a result, the landlord has limited incentive to carry out energy efficiency upgrades to the building, heating and cooling system or appliances.

Previous efforts for providing province-wide low-income CDM programs have failed to sustain momentum. In 2007, the Ontario Power Authority (OPA) offered three province-wide low-income conservation initiatives following an October 2005 ministerial directive. These programs lasted only a year. From 2008 to 2010, no province-wide low-income programs were offered, although Local Distribution Companies (LDCs) could apply for OPA funding to create a custom low-income program. In July 2010, the Minister directed the OPA to design, implement and fund an electricity CDM program for low-income residential consumers as part of its suite of province-wide CDM programs.

The OPA's low-income residential CDM program, to be co-ordinated with conservation programs offered by natural gas utilities, was expected to launch in May 2011, but has been delayed. The program will offer a free home energy audit, free direct installation of energy efficiency measures, and in-home conservation education on issues such as time-of-use prices and conservation behaviour.[62] Low-income households living in multi-family buildings, including social housing, are eligible for incentives under the OPA's Business Retrofit Program. LDCs can also apply to the Ontario Energy Board to deliver a custom low-income CDM program, however rules relating to OPA program duplication still apply.

The ECO commends the province for developing a province-wide low-income CDM program and encouraging a co-ordinated approach with natural gas utilities on program delivery. Lessons learned from this collaborative model should be extended into other conservation programs.

It remains to be seen, however, the results that will be delivered or whether the commitment to low-income CDM can be sustained. If previous experience is any indication, mandating low-income programs will not necessarily produce significant results. A 2005 directive to the OPA set a target of 100 megawatts (MW) in electricity savings from low-income and social housing consumers. However, as noted in the ECO's Annual Energy Conservation Progress Report – 2009 (Volume One), only three MW of savings was achieved.[63] Furthermore, given limited resources and the desire to achieve performance incentives, LDCs may keep their participation in low-income programs at a minimum level, as these programs may deliver lower energy savings than other types of conservation programs.[64]

ECO Comment

The ECO is encouraged that CDM programs will be available for all customer types, including a targeted low-income program. However, despite positive developments, the ECO also notes several areas of concern.

Encouraging or Discouraging Co-operation?

Although the OEB was specifically mandated to encourage opportunities for co-ordinating CDM programs between distributors and other relevant entities, the ECO is concerned that the centrality principle may have the opposite effect. During the Code consultations, stakeholders commented that having to prove centrality is onerous and could act as a disincentive for co-operation with other electric and natural gas utilities or organizations.

The Code does not differentiate how (or if) the centrality principle would apply to different types of collaborating entities (i.e., another electric utility, natural gas utility or other entity). For example, in the OEB's review of the conservation framework for natural gas utilities, OEB staff recommended that joint programs between natural gas and electric utilities attribute energy savings based on the energy source delivered (i.e., all electricity savings would go to the electric utility and all gas savings to the natural gas utility). It is unclear if the Code would allow for such an arrangement or if, as the Code currently stipulates, the electric utility would first have to prove centrality (e.g., that it contributed at least 50 per cent to the program before it could claim all the electricity savings).

Furthermore, the centrality principle may entice LDCs to duplicate, rather than leverage existing or develop new programs. For example, if two LDCs wish to deliver a similar program in their respective distribution areas, instead of collaborating on program design, the two utilities may choose to independently develop the same program. Although this would result in unnecessary duplication of resources, by avoiding collaboration both utilities can claim the full amount of savings from their distribution area without having to prove centrality.

All the Responsibility with None of the Freedom

The ECO is concerned that LDCs may unfairly be held responsible for OPA programs, in the event these programs do not perform as expected. While LDCs did participate in the design phase of OPA programs, they have little flexibility to improve or enhance them. Contracts between the OPA and LDCs do not allow LDCs to customize OPA programs to fit their particular distribution area. Furthermore, by ministerial direction, LDCs cannot apply for BAPs that duplicate an OPA CDM program. The CDM Code defined duplication to include differences in incentive levels, qualification requirements, technology specifications, marketing approaches or budgets from an OPA program.

The OEB's definition of duplication caused concern for many stakeholders. Though most agreed in principle that duplication of OPA programs should not be allowed, LDCs believed the definition was too restrictive, rendering much, if not all, LDC program innovation as duplicative. For example, utilities that were early adopters of *peaksaver*® argued that they needed to take a more creative approach, such as innovative marketing or greater incentives, to encourage higher participation rates. However, under the Code, such efforts could be interpreted as duplicative.

The ECO strongly disagrees with the OEB's definition of duplication. If an OPA program is not successful in uptake, LDCs have little opportunity to adjust programs as necessary, regardless of the potential increase in program results. Furthermore, the list of ineligible features in the definition of duplicative programs is so restrictive it may limit LDC innovation in BAPs, effectively centralizing control of most CDM programs with the OPA.[65] The ECO believes the OEB's overly prescriptive interpretation of duplication goes against the spirit of the *GEGEA*. LDCs are in the best position to tailor CDM programs to be more effective and suitable for their customers. With mandated targets, it is also in the LDCs' best interest to deliver the most effective and efficient programs.

The ECO strongly disagrees with the OEB's definition of duplication. If an OPA program is not successful in uptake, LDCs have little opportunity to adjust programs as necessary, regardless of the potential increase in program results.

Sustaining Momentum

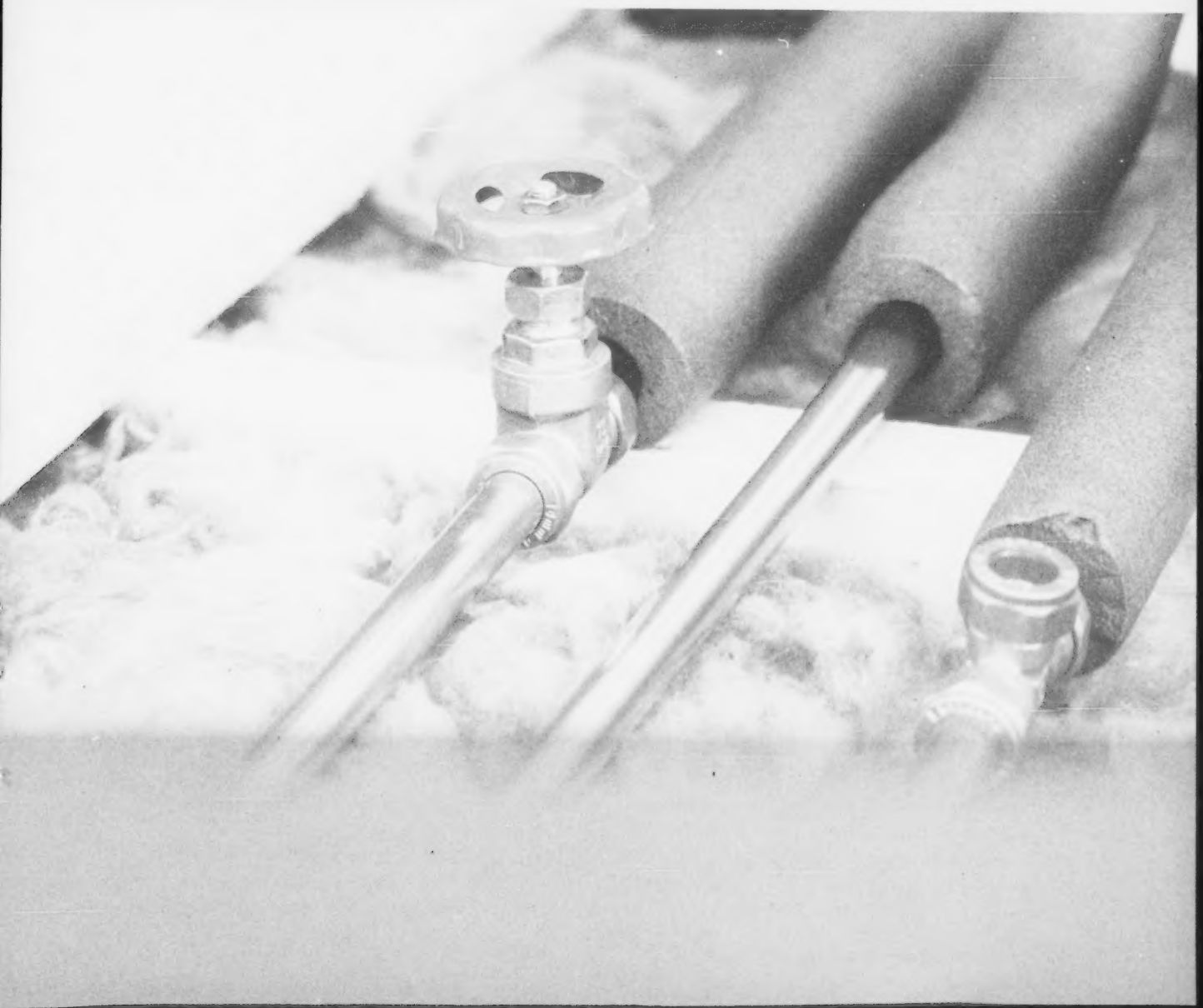
The CDM Code mandates that only initiatives starting January 1, 2011 and ending December 31, 2014 will count towards LDC targets. As a result, LDCs will likely ramp down their programs before 2014 to ensure all savings achieved are credited towards their targets. This, in addition to the late start of OPA programs, will effectively shorten the timeframe for delivering CDM programs, from four to three years.

To create a sustainable conservation culture, LDCs require long-term commitment. The current framework with short-term program funding hampers the ability of LDCs to engage in long-term CDM planning. Furthermore, a long-term commitment would allow LDCs to develop CDM programs with a longer payback that can deliver significantly greater savings.

There are currently no timelines in place to review and prepare for the next CDM framework. An important lesson learned from this process is the need to have a clear framework ahead of time to ensure momentum is sustained.

The ECO recommends that the Ministry of Energy initiate the next Conservation and Demand Management Framework, which would include guaranteed funding, by January 1, 2014.

6: Budget Freeze for Natural Gas Conservation: Who Will Pick Up the Cheque?



6.1 The OEB Determination

On March 29, 2011, as part of its review of guidelines dealing with the conservation activities of natural gas distributors (case #EB-2008-0346), the OEB issued a letter stating that the demand-side management (DSM), another term for conservation, budgets for Ontario's natural gas utilities would be limited to their existing levels for the next three years. This decision was somewhat surprising, as Board staff had recommended an increase in conservation spending that would more than double Enbridge Gas Distribution's DSM budget and increase Union Gas' DSM budget by more than 50 per cent by 2014, relative to 2011 spending levels.[66] In addition, both utilities had expressed support for an increase in DSM spending[67] and the Minister of Energy had urged the Board to "consider expanding both low-income and general natural gas DSM…efforts relative to previous years."[68]

The Board based its decision to freeze gas utility DSM budgets on several arguments.

- A more mature consumer market, with public and private entities providing energy efficient products and services, has led to consumers implementing conservation measures without the need for taxpayer or ratepayer funded incentives or programs. The availability of ratepayer-funded DSM programs may discourage market-driven activities.
- Higher minimum efficiency standards and the high penetration of traditional DSM measures mean that much of the "low-hanging fruit" for conservation programs has been picked. DSM programs were originally intended to achieve gas savings above what would naturally result from market forces and higher efficiency standards. Future savings will be more expensive to achieve.
- The justification for cross-subsidies (transferring funds from non-participants to participants in conservation programs) to fund DSM is eroding. To achieve savings, future conservation efforts may need to focus on deep measures, such as whole-house retrofits that will have a higher unit cost, which increases the risk of cross-subsidization.
- The federal and provincial withdrawal from deep measure programs such as the Home Energy Savings Program "should signal a cautionary approach in considering a significant expansion of ratepayer funded deep DSM programs."[69]

The Board also commented that "to the extent non-market support continues to be required for these [DSM] services beyond that available from the current level of ratepayer funding, the Board believes that alternative sources of funding would be more appropriate,"[70] an apparent suggestion that taxpayer funding from government would be preferable.

At the same time that the Board announced its decision on budget levels, it invited comments on a number of other issues related to the natural gas DSM framework. The ECO will review these issues in a future report. However, given the importance of the budget to the success of any conservation efforts, the ECO believes it appropriate to make some observations on the Board's arguments on this issue now.

ECO Comment

Given that the ECO has previously stated support for the expansion of conservation spending by gas utilities,[71] it is not surprising that the ECO is disappointed in the Board's decision. The ECO believes that the freeze in gas utility DSM budgets will have a detrimental impact, reducing conservation investment in Ontario below societally optimal levels.

Given that the ECO has previously stated support for the expansion of conservation spending by gas utilities, it is not surprising that the ECO is disappointed in the Board's decision.

It is worth examining each of the key arguments the Board provided for its decision.

Consumers are implementing conservation measures without incentives. It is certainly true that the marketplace for energy efficiency and conservation products is more robust than it was a decade ago. This is good news. However, the savings that consumers receive from conservation investments (in the form of reduced natural gas costs) do not reflect the full value of conservation. The avoided system cost (i.e., the marginal cost) from saving a unit of gas is greater than the average cost. This is referred to as the system benefit, which lowers bills for all ratepayers because gas transportation and storage costs are lower, and

consumers undertaking conservation investments are not credited for this benefit or for the environmental benefit of avoiding GHG emissions. Therefore, from a purely economic perspective, if supporting incentives are not provided, consumers will not invest in conservation to the societally optimal level. In the absence of pricing changes to correct this issue, financial incentives to consumers for conservation serve a necessary purpose.

The cheap and easy conservation savings are gone. Again, partially true, particularly for long-standing gas DSM programs such as low-flow showerheads that are close to full market penetration. However, as the ECO has previously noted, gas utility conservation programs in 2007 to 2009 delivered between 7 and 14 dollars in net benefits for every utility dollar spent.[72] Gas utilities are far from being unable to find cost-effective energy conservation investments.

Conservation programs transfer income from non-participants to participants. True, however, the rules of utility conservation funding minimize the amount of this income transfer and also enable broad participation of ratepayers in conservation initiatives.[73] Also, as noted above, all utility customers including non-participants benefit from conservation through lower system costs.

The government's exit from funding conservation programs suggests that these programs were failures. This is perhaps the easiest argument to refute. The Minister's letter to the OEB urging an increase in conservation spending suggests an alternative explanation – that a cash-strapped government was hoping to transfer some of the costs of conservation from taxpayers to ratepayers, by having gas utilities offer some of the features of the cancelled government programs. This explanation is consistent with an earlier action by the government. Prior to ending funding for government conservation programs, the Ministry of Energy and Infrastructure passed a regulation (O. Reg. 66/10, made under the *Ontario Energy Board Act, 1998*) to recover $54 million in costs for government conservation programs from electricity ratepayers.[74] A similar regulation was under consideration for natural gas ratepayers, but was never finalized.

On the issue of whether taxpayers or gas utility ratepayers should fund conservation, there are arguments on both sides. To the degree that conservation programs partially internalize the environmental costs of fossil fuel consumption and also avoid system costs, it makes sense for ratepayers to pay. In cases where there are large-scale monetary transfers that may exceed the system value of the conservation savings (e.g., fully-funded deep measure low-income programs), or where conservation programming is experimental in nature (e.g., research & development, pilot programs), it may make sense for government to play a funding role.

What is clear, however, is that the decisions of both the government and the OEB to restrict conservation spending and hope that the gap will be filled by the other party have the consequence of hurting the public good. Given that direct use of natural gas comprises a much larger share of Ontario's final energy consumption and GHG emissions than electricity does,[75] the systematic underfunding of natural gas conservation is perverse. Someone needs to step up to the plate.

The ECO recommends that the Ministry of Energy clarify the appropriate roles of the government and gas utilities in funding natural gas conservation, with the goal of increasing overall funding.

7: Smart Grid

According to Ontario's LTEP, provincial electricity demand will grow by 15 per cent between 2010 and 2030. This means that Ontario's electricity system will need to provide 165 TWh of total generation by 2030. The increase in demand for electricity will strain the existing power grid, requiring increased investment in both additional power generation and infrastructure to maintain system reliability. With this anticipated growth, a shift towards a more efficient use of the electricity system is being made. This will transform the existing grid into the "smart" grid. In order to recognize its full potential, it is important to first understand the concept of the smart grid.

7.1 What is the Smart Grid?

Smart grid is the term used to describe the next generation of the electricity delivery system. It does not refer to just one technology, but instead refers to different technologies working together and managing electricity in a novel way. It includes customer control aspects, such as smart meters, TOU rates and load control capabilities. It also includes the idea of utility flexibility, where smart grid technologies will enable micro-generation and distributed generation, and reduce the need for transmission investment through a more efficient use of the existing transmission system. Additionally, it includes the idea of adaptive infrastructure, such as charging infrastructure for electric vehicles and distributed energy storage, which can make use of energy produced during off-peak times.

Fundamental to this initiative is the overlaying of a two-way communication network on top of the existing transmission and distribution system. Instead of the grid remaining limited to top-down electricity flow, there will be two-way power flow capabilities across the transmission and distribution networks, allowing for an increase in the number of smaller electricity storage and generation opportunities across the system.

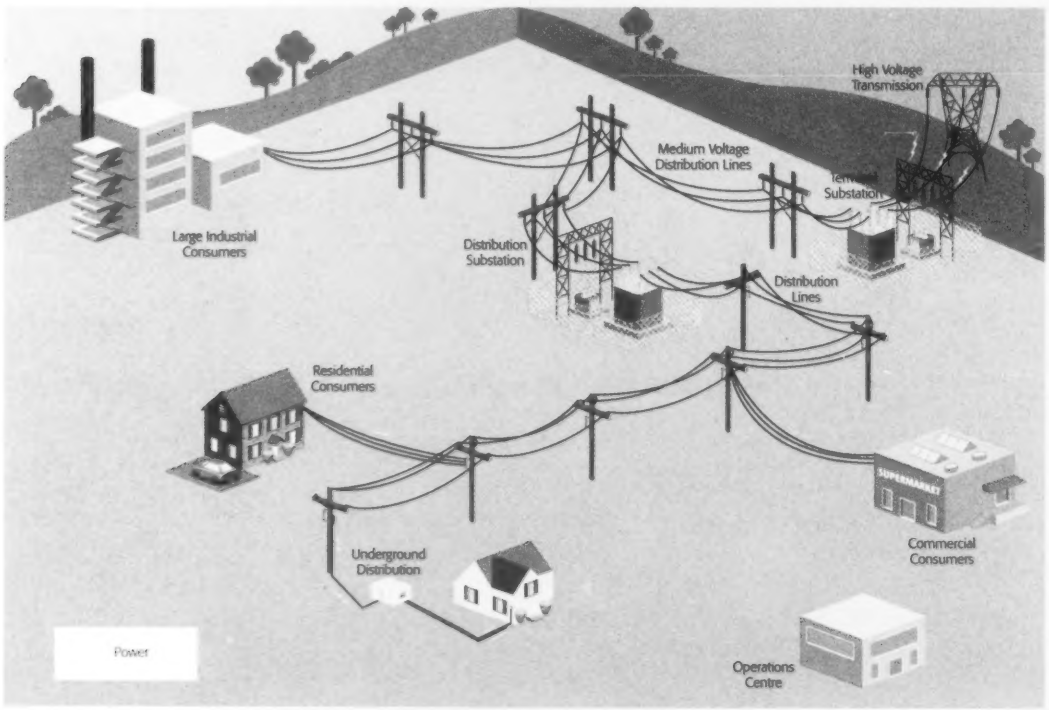


Figure 5: Today's Distribution System

Through the installation of sensing, monitoring, protection, and control technologies, the ability of the grid to incorporate demand response and distributed renewable energy generation will increase. This allows consumers to interact with and manage or modify their electricity usage more effectively than ever before. The smart grid even has the potential to extend down to the appliance level, with new appliances being developed to communicate with the electrical grid and to shut off during times of high energy demand and prices. This communication system can also enable LDCs to recognize and identify electrical problems as they occur. LDCs will be better able to locate and manage power outages through sensors along the grid, reducing fault impacts and minimizing grid disruption.

Through the installation of sensing, monitoring, protection, and control technologies, the ability of the grid to incorporate demand response and distributed renewable energy generation will increase. This allows consumers to interact with and manage or modify their electricity usage more effectively than ever before.

The smart grid can also improve the system economics by reducing electricity losses[76] during delivery and therefore allowing generated electricity to be used more efficiently. This also reduces the environmental impact of generation. For example, in Ontario it is estimated that about 4 per cent of electricity is lost at the distribution level.[77] At the transmission level, losses are typically between 2 to 3 per cent, although incremental losses can be as high as 30 to 40 per cent depending on the system configuration, the location of generators, demand and weather patterns.[78] This means that typical electricity losses between the point of generation and end user are around 6 per cent. By reducing inefficiencies, more electricity is available to end-users instead of lost during delivery.

A focused and methodological approach to implementing the smart grid is necessary to ensure its success. Key elements of the smart grid include smart meters, distributed storage, and distributed generation. The following is a summary of these components.

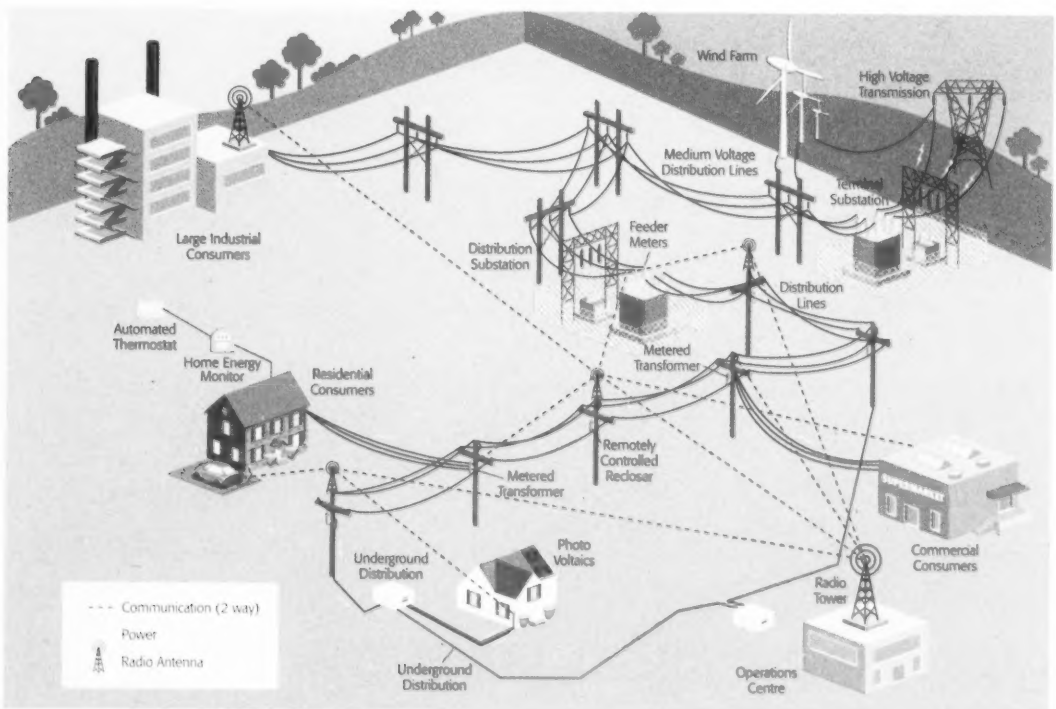


Figure 6: Tomorrow's Smart Network

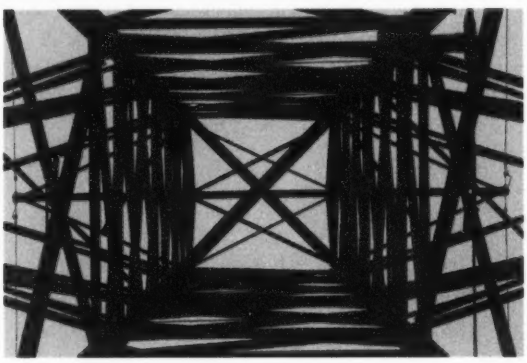
7.1.1 Smart Meters

As described in the ECO's Annual Energy Conservation Progress Report – 2009 (Volume Two), smart meters are replacing traditional analog meters in Ontario. Unlike their analog counterparts, they digitally record and measure electricity usage on an hourly basis. Automated meter readings are sent remotely to a central data management centre, which is used to generate customer invoices. If utilities provide consumers access to their electricity consumption data in a timely and user-friendly fashion, this can be an important energy conservation tool. Consumers can monitor their electricity loads to identify sources of electricity waste and to respond to price signals by shifting some of their electricity use to off-peak times. Several Ontario utilities have taken the lead by providing Internet applications that show users their metered electricity consumption data.

With the implementation of smart meters in Ontario, the data exists for Ontarians to understand how they use their electricity. The challenge now is to manage the available data and make the most of this new information.

7.1.2 Distributed Generation

Distributed generation refers to a non-centralized energy generation model, where generation projects exist across the province. These generators can connect to the low-voltage distribution lines, rather than the high-voltage transmission lines, in order to supply power to the electricity grid.

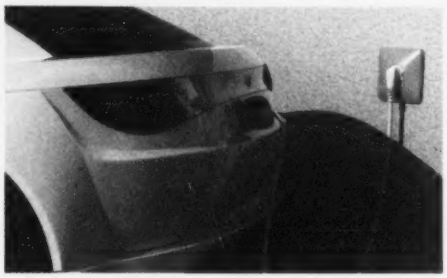


Distributed generation includes intermittent renewable supply, such as wind and solar, and can also include natural gas plants, thermal (geothermal) plants, bioenergy plants, combined heat and power plants and hydroelectric facilities. Ontario has committed to incorporating large amounts of non-hydroelectric renewable generation into the system. By 2012, about 5,800 MW of renewable generation is expected to be part of Ontario's supply mix, and by 2018 that figure is expected to be 10,700 MW. Given this commitment, there is a growing need to connect smaller generation facilities to the high voltage transmission network, as well as to the distribution network. For optimal network performance, both distribution and transmission systems must be able to handle the two-way flow of power.

An important difference between distributed generation and centralized generation connected to the transmission grid is that the IESO is unable to monitor and control power flows within distribution networks. As distributed generation becomes a larger part of Ontario's generation mix, a more robust flow of information may be needed to ensure that the IESO can continue to perform its role of matching electricity supply and demand in real time.

7.1.2.1 Balancing Supply and Demand – An Old Challenge for a New Grid

A constant balance between supply and demand is required to maintain the integrity of the electricity grid. In order to ensure continued reliability as the grid is modernized, a challenge will be demand forecasting. It will need to be modified to account for consumers responding to price signals.



Electricity prices will likely be the main motivator for consumers adopting new energy management technologies.[79] A key driver of prices is electricity demand. Power system operators have established demand (or load) forecasting models and are able to accurately forecast future demand. As consumer patterns become altered based on price signals, the demand curve will evolve away from that predicted by current models. This response is expected to have an impact on price formation, which is important because these prices are used by market participants (e.g., generators and distributors) to determine operating and planning activities.

As noted earlier, the amount of renewable and distributed generation on Ontario's grid is expected to increase significantly, and this may significantly affect the characteristics of the grid. For example, the error in a 12-hour forecast for wind generation can range from 20 to 100 per cent.[80] The variability of the wind energy forecast directly contrasts with the accuracy of demand forecasting, and requires the Independent Electricity System Operator (IESO) to adapt its operation of the electricity system to accommodate variable generation. The IESO is exploring how to integrate renewable energy without compromising reliability, safety and efficiency in its operations. For this, it is engaging stakeholders until September 2011 to discuss integration, particularly focusing on forecasting, dispatch, and visibility (i.e., the ability of the system operator to monitor power production) for wind and solar generation.[81]

The IESO's Alternative Technologies for Regulation Demonstration Project

Ontario's electricity Market Rules[82] were recently amended to allow non-generation resources to offer grid-balancing regulation of the electricity system. This will assist Ontario's electricity system with incorporating higher levels of variable generation that will be a direct result of renewable energy generation. A pilot project was initiated with two companies in late 2010 allowing these large consumers to respond to IESO signals and adjust consumption in response to variable generation. Traditionally, this service was supplied by generators through their automatic generation control capability, which provides a second-by-second balancing of supply and demand on the grid. The pilot project is intended to demonstrate that electricity consumers, and not just electricity generators, can offer this service.[83]

7.1.3 Energy Storage

The smart grid will make the entire electricity grid a more dynamic system. Part of this will come from increased flexibility for distribution utilities. As discussed above, distributed generation is a key aspect of the smart grid and its optimization goes hand-in-hand with energy storage.

Ontario is increasing the amount of renewable, variable generation which could occasionally result in the generation of surplus baseload energy at times of low demand and high renewable output. If there is a distributed energy storage system available for utilities to use, the system can capture the excess baseload energy while it is being generated and deploy this energy once the demand increases.

When considering the variability of wind on a daily basis, the importance of storage becomes clear. In terms of installed system capacity, wind accounts for 3.6 per cent of Ontario's total supply mix, but will increase to 10 per cent by 2030.[84, 85] The IESO estimates that only 13 per cent of the installed wind capacity can be considered to be available during summer peak and 32 per cent during winter peak.[86] This is an average. In any given hour, output can vary from near zero to 100 per cent of capacity.[87] Storage of variable generation can help moderate electricity prices because off-peak energy can be used during mid- and on-peak times. Distributed energy storage can help the grid remain stable, with the potential to make it a more efficient and reliable system that leads to lower operating costs in

the long term. Overall, distributed storage has many benefits, including enhanced power quality, frequency, load-following, spinning reserve, and load-levelling.

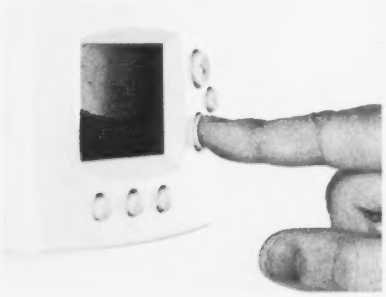
In the longer term, several technologies have the potential to be viable in Ontario, including: advanced batteries; flow batteries; flywheels; pumped hydroelectric storage (site specific); compressed air storage; superconducting magnetic energy storage; and thermal storage. Due to high capital costs and the relative immaturity (including limited operating experience) of these technologies, Ontario is still in the process of investigating the potential for storage technologies.

The amendment to the Supply Mix Directive, issued in September 2008 by the then Minister of Energy and Infrastructure to the OPA, requested that the OPA review the potential for pumped hydroelectric storage for providing energy during times of peak demand. The LTEP, issued after the 2008 directive, notes that energy storage is an "important part of the move to a Smart Grid,"[88] yet it does not provide a comprehensive overview or proposal requiring energy storage and pumped storage to be incorporated into Ontario's supply mix. In short, the LTEP does not follow-up and advance the earlier directive with respect to energy storage.

Storage is discussed in the new Supply Mix Directive. This directive supersedes any previous directives and indicates that potential electricity storage must be considered, without providing substantial detail.

7.2 A New Planning Paradigm – How the Smart Grid Unites Transmission and Distribution

To realize the full benefits of distributed energy storage, generation, and smart meters, the transmission and distribution networks must become better integrated so that all parts can work together effectively.



The current grid was designed to accommodate centralized power generation, where electricity is generated at a particular power plant and transported away from the power plant through a series of high voltage transmission wires. Ontario has about 30,000 km of transmission lines, which are mostly owned and operated by Hydro One. The transmission system consists predominantly of 500 kilovolt (kV), 230 kV and 115 kV transmission networks. Distribution companies take the high-voltage electricity from the transmission lines and "step-down" the electricity to a low-voltage level, making it safer and usable in appliances and equipment. Distributors own and operate the distribution system and serve customers within a particular geographic region and deliver the majority of electricity consumed in Ontario to individual customers, with the exception of large industries which are usually directly connected to the transmission network. There are currently about 80 distribution companies in Ontario. Ontario's grid interconnects with neighbouring jurisdictions, including Michigan, Minnesota, New York, Manitoba and Quebec.

The design described above meant that physical separation between the transmission and distribution systems was ingrained in the system from the beginning – they were considered separate functions with responsibility divided between the operators. This separation can be detrimental to the smart grid because it needs to function as a single unit, with distributed generation and storage being incorporated at both the transmission and distribution levels.

Some aspects of the smart grid are already incorporated into the design of Ontario's transmission network. For example, the transmission system permits two-way power flow and includes monitoring of equipment and power flow. Transmission line equipment also enables remote control. Embedded automation in the system helps maintain reliability in the case of an emergency.

7.3 Ontario's Smart Grid – the Regulatory and Policy Framework

7.3.1 Enabling Legislation

With the passage of the *GEGEA*, Ontario introduced enabling legislation to implement a smart grid design. As a result of *GEGEA* amendments to the *Electricity Act, 1998*, the following broad definition of the smart grid was introduced; this definition

demonstrates both the centrality of the smart grid to the *GEGEA's* policy direction, as well as the complexity of transforming the transmission and distribution systems:

> For the purposes of this Act, the smart grid means the advanced information exchange systems and equipment that when utilized together improve the flexibility, security, reliability, efficiency and safety of the integrated power system and distribution systems, particularly for the purposes of,
>
> (a) enabling the increased use of renewable energy sources and technology, including generation facilities connected to the distribution system;
>
> (b) expanding opportunities to provide demand response, price information and load control to electricity customers;
>
> (c) accommodating the use of emerging, innovative and energy-saving technologies and system control applications; or
>
> (d) supporting other objectives that may be prescribed by regulation.

The *GEGEA* also expanded the *Ontario Energy Board Act, 1998* so that the OEB is responsible for promoting conservation and the timely expansion or reinforcement of transmission and distribution systems to connect renewable energy generation facilities, while facilitating the implementation of a smart grid in Ontario. The *Ontario Energy Board Act, 1998* was also amended to allow the Minister of Energy to issue directives to the OEB for establishing, implementing, or promoting the smart grid. Other changes include the requirement that licences for transmitters and distributors describe plans, as specified by the OEB or by regulation, for the development and implementation of the smart grid.

7.3.1.1 Regulator of its Own Policies? The Role of the OEB

The Ontario Energy Board (OEB) is responsible for regulating Ontario's electricity and natural gas sectors in the public interest. It serves a necessary purpose to protect consumers from natural monopolies in the energy sector.

The objectives of the OEB's regulation of the electricity sector are to promote conservation in a manner consistent with government policy and to protect the interests of consumers with respect to prices. These objectives could cause ambiguity in the OEB's interpretation of its priorities. Its functions include setting transmission and distribution rates, setting generation rates for Ontario Power Generation's nuclear and baseload hydroelectric facilities, and approving the budget and fees of electricity agencies. In addition, the OEB licences all market participants and approves construction of new electricity transmission lines that are longer than two kilometres. It monitors the electricity sector market and reports to the Minister of Energy on the efficiency, fairness, transparency, abuse or potential abuse of market power. The OEB may even be asked to review the Independent Electricity System Operator's (IESO) market rules and consider appeals of IESO orders. It is clear that the OEB is involved with many facets of Ontario's electricity system.

The OEB's role in approving ratepayer funding for projects makes it a key gatekeeper in the implementation of energy policy in Ontario. While the regulatory model has served Ontario well for protecting consumer interests, there is some question as to whether the OEB is the appropriate choice to achieve the more innovative objectives that it was given through the *Green Energy and Green Economy Act, 2009* – promoting renewable energy and conservation, and facilitating the implementation of the smart grid. There is a risk that the government has delegated too much responsibility to the OEB for making policy in these areas, which may conflict with the OEB's traditional regulatory role.

7.3.2 Minister's Directive

On November 23, 2010, the Minister of Energy issued a directive to the OEB requiring it to take steps to establish, implement and promote a smart grid. Customer control, power system flexibility and adaptive infrastructure were the three broad objectives provided to the OEB. The directive also included a list of ten policy objectives that the government has set for implementing a smart grid. One objective calls for the consideration of environmental benefits in promoting clean energy technologies, conservation and more efficient use of existing technologies. These policy objectives will be used by the OEB to develop direct guidance to LDCs and to evaluate smart grid plans submitted by LDCs.

7.3.3 The Ontario Energy Board's Smart Grid Working Group

Pursuant to the November 2010 directive, the OEB is to provide guidance regarding its expectations in relation to the establishment and implementation of a smart grid. This guidance is to be provided to LDCs, transmitters, and all other regulated entities whose fees are reviewed by the OEB.

To accomplish this, the OEB established a Smart Grid Working Group (SGWG) to provide advice on the technical details for implementing a smart grid plan in Ontario. The group consists of 25 members including industry, the IESO, Measurement Canada, and LDCs. The SGWG is focusing on the directive's policy objectives with a special emphasis on the Regional Smart Grid Plans, which are designed to achieve a co-ordinated approach for distributors. This will allow LDCs to share pilot project information and results, as well as engage in similar procurement processes. Through alignment of the procurement processes, LDCs can benefit from economies of scale.

An inaugural meeting of the SGWG took place on March 1, 2011 and the working group will meet bi-weekly for approximately four months. Through these meetings, the group is providing technical advice to the OEB, which will help the OEB prepare a discussion paper. This discussion paper will form the foundation for future OEB consultations concerning smart grid regulation and guidance documents.

7.4 The Ontario Energy Board's Green Energy Act Plan for Distributors

The OEB released the document *Distribution System Plans – Filing under Deemed Conditions of Licence* (EB-2009-0397) on March 25, 2010. It provides the filing requirements based on the policy direction contained in the guideline *Deemed Conditions of Licence: Distribution System Planning* (G-2009-0087) issued by the OEB in June 2009 for filing distribution system plans with respect to connecting renewable generation and developing the smart grid.

Beginning in 2012, and for each subsequent year, cost of service rate applications for every LDC must contain a Green Energy Act Plan (GEA Plan) as part of each application.[89] There are two types of plans that can be submitted: a Basic GEA Plan or a Detailed GEA Plan. Both cover five-year horizons and discuss the distributor's ability to connect renewable generation, as well as highlight any expansion or reinforcement needed to accommodate renewable generation. In addition, each LDC is required to submit its GEA Plan to the OPA for comment prior to filing, and the OPA's comments must be included in the submission to the OEB.

To date, the OEB has not required distributors to file smart grid development plans in their GEA Plans since the OEB awaited additional ministerial direction, which has now been provided by the November 23, 2010 directive. The GEA Plan must include a description of activities and expenditures related to smart grid development if the distributor is seeking the recovery of those costs. Successful cost recovery is subject to the OEB's review.

Smart grid development activities and expenditures are limited to demonstration projects, studies or planning exercises, and education and training. The OEB will keep an on-line repository of any studies and demonstration projects, including LDC evaluations discussing the performance, benefits and lessons learned. This will allow distributors to share best practices and avoid unnecessary duplication.

7.4.1 Other Smart Grid Activities in Ontario

The Ministry of Energy's Smart Grid Fund

In the 2009 Ontario Budget, the government committed $50 million over a five-year period to "enable the research, capital and demonstration projects necessary for the development of a smart grid in Ontario."[90] In January 2011, the Ministry of Energy issued a Request for Information to help it develop a new Smart Grid Fund. The ministry posted an Information Notice on the Environmental Registry and the fund was launched in the spring of 2011. It is anticipated that approved projects will receive funding as early as August.[91]

Hydro One

Hydro One has been working towards implementing a smart grid and has established five value drivers for its smart grid work. These drivers are increased reliability, increased operations effectiveness, faster restoration, customer enhancement using smart meter/analytical tools to effect conservation, and a lower carbon footprint.[92]

In its 2010 and 2011 distribution rates application in front of the Ontario Energy Board, Hydro One identified its plans to look at implementing the smart grid beyond the smart meter level. The company is conducting pilot studies of new systems, including an assessment of geographic information system mapping of its infrastructure, distributed generation technology trials, and an assessment of standards and operating procedures. The utility also intends to test plug-in hybrid electric vehicles in its "Smart Zone" pilot project.

The "Smart Zone" pilot project in the Owen Sound region will evaluate the effectiveness of different technology systems. The company is in the first phase of the project, with a focus on telecommunications integration. It is also examining different business processes, interfaces, and systems and security management tools needed for the smart grid's success. The first phase is expected to last until 2013, after which Hydro One will begin implementing various smart grid components in other areas of its distribution territory and its transmission network across the province.

General Electric Canada

In March 2011, General Electric Canada (GE) announced it would establish a $40 million project in Markham, Ontario. The project – GE Grid IQ Innovation Centre – will be responsible for developing and manufacturing smart grid products for Ontario and world markets. It will also include a demonstration and lab facility for GE's products and services. The $40 million project is receiving $7.9 million from the Ontario government. The centre will focus on distribution automation, electrical system protection, micro-grid control and cyber security.

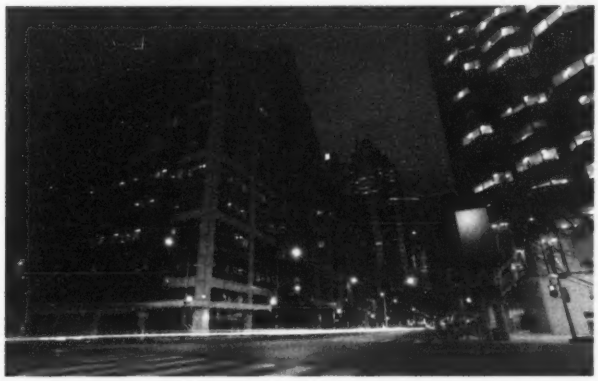
ECO Comment

The smart grid has the potential to improve electricity grid operation while enabling the integration and adoption of renewable generation and other innovative electricity technologies. It can also serve as a platform to enhance conservation and energy efficiency. It is therefore commendable that the government has begun the process of implementing a smart grid policy.

If the smart grid is to succeed in Ontario, the ECO believes that one entity must be charged with establishing the vision and providing the overall leadership necessary to guide all players towards the common goal of modernizing the grid.

If the smart grid is to succeed in Ontario, the ECO believes that one entity must be charged with establishing the vision and providing the overall leadership necessary to guide all players towards the common goal of modernizing the grid. The ECO urges the Ministry of Energy to engage the public in discussions on both the vision and the manner by which smart grid development should be led. To initiate this dialogue, a white paper should be posted on the Environmental Registry as a proposal notice for public comment.

In the ECO's view, the critical element with respect to leading the implementation of the smart grid is that it be directed by an organization with a perspective of the electricity system *as a whole* and one that can guide all organizations with grid-related responsibilities toward a unified vision. Presently, various grid responsibilities are partitioned between the IESO, OEB, OPA, Hydro One, LDCs (and to a lesser extent generators) and reflect their individual roles and objectives. This division of responsibilities is suitable for the functioning of the current grid. However, none of these organizations control all physical assets of the grid, nor is there a sole organization with the mandate and latitude to make decisions on allocating resources to build a two-way information-based smart grid. Moreover, the implementation of smart grid technology may require realigning or redefining the mandate of some of these organizations, possibly placing them in a position of conflict of interest were they to be the leader of smart grid development policy.



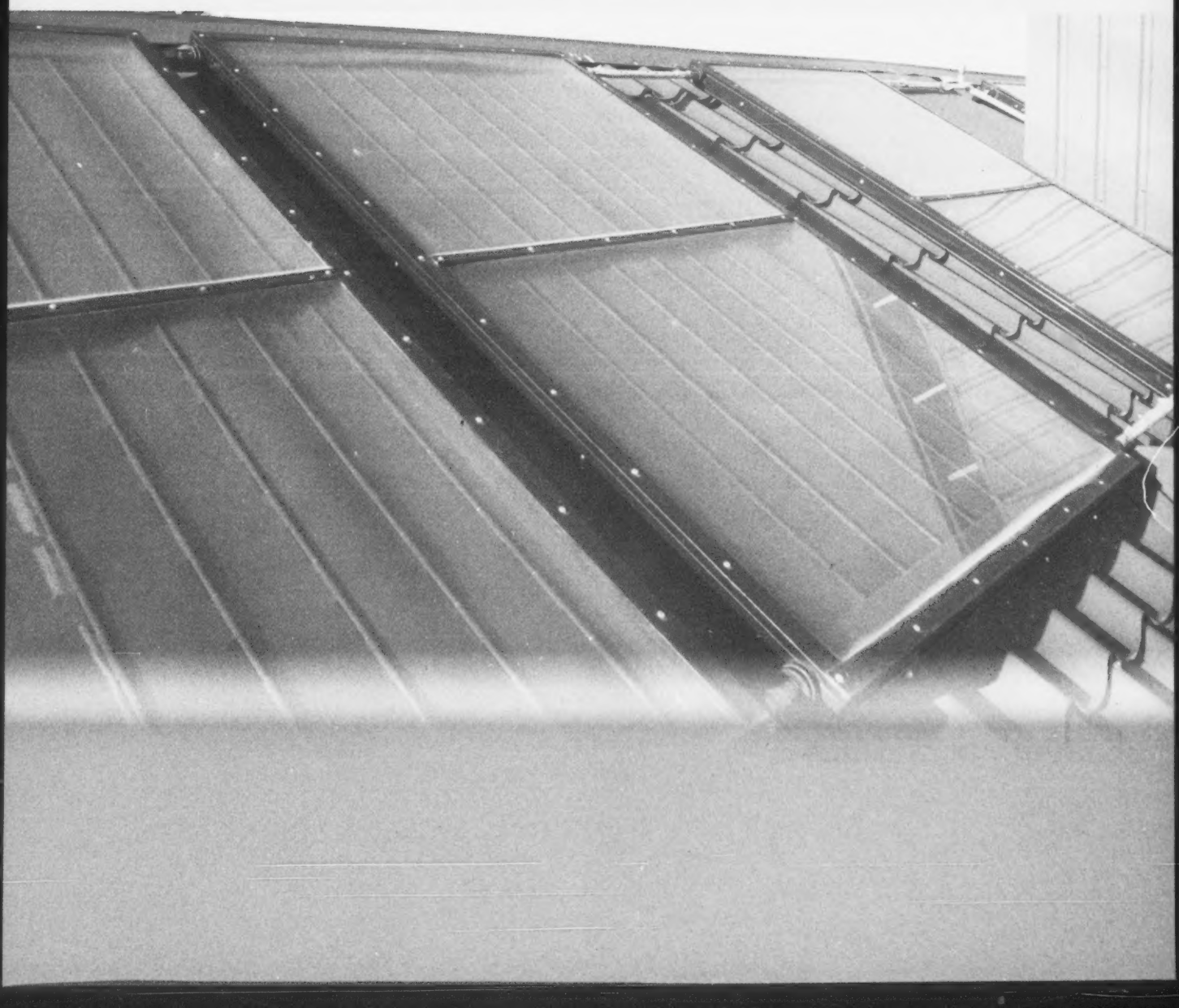
Finally, the ECO notes that a policy asymmetry exists between LDC initiatives to conserve energy on the customer versus the utility side of the meter. Previously, many LDCs used conservation funding to undertake infrastructure investment projects to reduce line losses.[93] Under section 3.1.5 of the new CDM Code, infrastructure investments of this nature cannot be classified as conservation measures. The Board's rationale for including this in the Code is the lack of efficiency standards for distribution infrastructure, making it difficult to classify capital project investments as CDM tools.[94] Despite the difficulties of classification, this type of infrastructure investment is necessary for a more efficient electricity grid.

A 2008 OEB study noted the majority of LDCs believed that the regulatory environment did not allow them to make investments to reduce distribution losses in an optimal fashion.[95] Therefore, incentives should be made available for such infrastructure investment to reduce line losses to overcome the barrier of the higher cost of efficient infrastructure and ensure that appropriate long-term system planning occurs. The ECO believes that the OEB's power to regulate the implementation of the smart grid provides an opportunity to rectify this imbalance.

A 2008 OEB study noted the majority of LDCs believed that the regulatory environment did not allow them to make investments to reduce distribution losses in an optimal fashion.

The ECO recommends that the Ontario Energy Board encourage and facilitate smart grid investments that reduce line losses, putting these investments on an equal footing with conservation investments.

8: Barriers to Alternative Energy Systems



Alternative Energy Systems

The ECO has a responsibility under the *EBR* to examine "barriers to the development or implementation of measures to reduce the use or make more efficient use of electricity, natural gas, propane, oil and transportation fuels." The ECO first examined barriers to energy conservation in the Annual Energy Conservation Progress Report - 2009 (Volume One). This year, the ECO has focused on barriers to conservation within a single topic area: the uptake of alternative energy systems.

Alternative energy systems reduce the need for non-renewable resources, such as oil, coal and natural gas, and reduce the greenhouse gas emissions associated with conventional energy systems.

Alternative energy systems reduce the need for non-renewable resources, such as oil, coal and natural gas, and reduce the GHG emissions associated with conventional energy systems. In addition to environmental benefits, alternative energy systems may also ease energy costs for consumers, stimulate the creation of "green-collar" jobs, and help establish sustainable communities with an improved quality of life.[96] Despite these many benefits, the uptake of alternative energy systems has been low (with the exception of solar photovoltaic [PV] installations as a result of the microFIT program) due to various obstacles. In this section, the ECO examines barriers that exist for newly constructed homes and neighbourhoods, as well as discusses a unique barrier for installing solar thermal in existing homes.

Examples of alternative energy sources or energy conversion systems include passive solar, geoexchange, solar thermal and solar PV systems. Homebuilders or owners can use a combination of these and other sustainable technologies to maximize efficiency and reduce energy use. For example, a homeowner can use passive solar to reduce overall energy requirements, geoexchange or solar thermal to supply low-grade heat for water and space heating, and solar PV to generate high-grade electricity for lights and appliances.[97]

These technologies can also be integrated on a neighbourhood scale to further support resilient energy for communities.[98] At a community level, an alternative approach to the current energy system is district energy – a system for distributing heat generated at a central plant to residences and businesses to heat space and water for multiple buildings in a neighbourhood. Current district energy systems typically obtain heat from cogeneration plants that burn fossil fuels, but renewable sources can be used. Cogeneration systems recover heat that would normally be wasted in electricity generation, and save fuel that would otherwise be used to produce heat or steam in a separate unit.

For additional information on these technologies, please see Appendix A of this report.

8.1 Barriers to Alternative Energy Systems in New Homes and Neighbourhoods

Energy efficient houses can yield significant lifetime cost savings for homeowners.[99] On the other hand, if buildings and neighbourhoods are built without energy efficiency in mind, inefficiencies can be "locked in" to the building stock for decades. Thus, it is important to avoid lost opportunities during the design and construction of new buildings and to adopt energy-efficient technologies. Retrofitting for alternative energy systems can be expensive and, depending on the initial design of the building or neighbourhood, may not be practical or even possible. With some 60,000 housing starts a year in Ontario,[100] the lost opportunities are enormous.

Why are passive solar design, geoexchange, solar thermal, solar PV and district energy technologies still achieving relatively low penetration in new residential developments? The key barriers, which are often interlinked, include regulatory, financial and capacity considerations.

Policy and Regulatory Barriers

The potential for policy and regulatory barriers exists at several levels, in part due to the variety of agencies and levels of government involved in energy planning. This includes the provincial government, gas and electric utilities and municipalities.

The most comprehensive solution would be for the province to amend the Ontario Building Code to make alternative energy systems mandatory rather than voluntary. Partial measures to use the Building Code to promote alternative energy systems are also possible.

The most comprehensive solution would be for the province to amend the Ontario Building Code to make alternative energy systems mandatory rather than voluntary. Partial measures to use the Building Code to promote alternative energy systems are also possible. A proposed change to the Building Code would require new homes to be built with at least one conduit to facilitate the future installation of a solar PV or solar domestic hot water heating system (solar "rough-in"), however, this change would not come into force until 2017.[101] The Building Code could also be amended to make it easier for houses with alternative energy systems to demonstrate compliance with the whole-house energy efficiency levels that the Building Code requires. For example, the "prescriptive packages" that builders use to meet the Building Code's energy efficiency requirements could include alternative energy systems, which they currently do not.[102]

Regulated utilities could also play a role in promoting the uptake of alternative energy systems, but it appears this role has been limited by OEB rulings and approvals. In 2009, the then Minister of Energy and Infrastructure issued a directive to the OEB noting gas utilities should be allowed to own "assets related to solar thermal water and ground source heat pumps," among other technologies.[103] However, the Board's ruling in a recent hearing on Enbridge's rates suggested that costs of such technologies should not be recovered from ratepayers – the cost and risk will have to be borne by the utility and its shareholders.[104]

Like gas distributors, electric utilities can develop custom conservation programs that promote alternative energy systems. Government policy, however, restricts the benefits that programs developed by electricity distributors can claim. As directed by the Minister, the OEB must consider load reduction from initiatives such as geothermal heating and cooling and solar heating in its definition of CDM.[105] However, as these programs must demonstrate cost effectiveness prior to OEB approval, the relatively higher capital costs and lower electricity cost savings may be an interlinked financial barrier prohibiting uptake of alternative heating and cooling technologies. Consequently, OEB approvals may currently be restricting the role that LDCs can play in promoting the uptake of alternative energy systems. The government should seek the advice of the OEB and OPA, who are responsible for the application of cost-effectiveness tests used in Ontario, on how this barrier could be addressed.

Pilot projects have shown that permitting and approvals processes within municipalities and other governmental bodies can be cumbersome or act as roadblocks to the successful incorporation of alternative energy systems. For example, a pilot project in Toronto for solar thermal retrofits found that high municipal permit costs and Building Code compliance requirements were barriers impeding uptake.[106] In many cases, the barriers may result from conservative practices among inspectors unfamiliar with the new technology, rather than the legal requirements within the Building Code itself.

Moving beyond individual houses to the neighbourhood level, the Provincial Policy Statement, 2005 states that planning authorities shall support energy efficiency through development patterns which promote design and orientation that maximize the use of alternative or renewable energy, such as solar.[107] To this end, the Ministry of Municipal Affairs and Housing (MMAH) has produced guidance documents for municipalities wishing to encourage energy efficient design.[108] However, MMAH does not have any performance indicators to determine whether this direction is achieving any effect on the ground.[109]

Financial Barriers

One of the most commonly cited barriers to the use of alternative energy systems in new homes is the up-front costs for the homebuyer. These capital costs vary depending on the technology chosen, but are particularly high for geoexchange and solar PV installations. "Split incentives" are also a problem: since designers and builders do not pay the resulting home's energy bills, their priority is to minimize capital costs for new homes in order to win bids and maximize profits.[110]

Some proponents of alternative energy systems believe the best method of increasing market share is to include these systems within "premium" house energy efficiency labels (e.g., ENERGY STAR®, LEED, R-2000). Premium labels can address the concern of split incentives by fostering a market premium for energy efficiency due to increased awareness of efficient buildings. However, a recent study noted that direct "incentives to builders are more likely to drive efficiency, because they directly offset incremental costs without requiring buyer awareness."[111] Without financial incentives, costs may remain a barrier.

There are currently no federal or provincial grants for new homebuyers or for builders wishing to invest in alternative energy technologies. Previously, funds and incentives existed for homeowners wishing to retrofit certain alternative energy technologies, but these have been discontinued (see section 8.2). Existing incentives focus on traditional energy efficiency measures (e.g., efficient air conditioners, boilers, etc.) rather than alternative energy systems. Builders can only obtain an incentive for alternative measures if they demonstrate that it is cost-effective.[112] The OPA's new home construction program provides builders with incentives to construct homes that include energy efficiency standards above the current Building Code.[113] However, as the ECO has previously noted,[114] the use of high discount rates in cost-effectiveness tests often penalizes measures that have high up-front costs, but deliver energy savings for long periods of time – a description that applies to many alternative energy investments.

Previous provincial and federal funding has generally focused on installations of alternative energy systems in individual projects or buildings, not the design of neighbourhood scale projects. However, in recent years, the federal government has allocated some funds directly for community projects and, indirectly, through support of external initiatives, such as the Federation of Canadian Municipalities' Green Municipal Fund.[115] In addition, the OPA has supported community initiatives in Toronto, Guelph, London, and East Gwillimbury. It has also provided funding assistance to the Canadian Urban Institute for research on energy and land use mapping and developed a Community Energy Partnership Program.[116]

Capacity Barriers

The lack of government incentives – or the uncertainty caused by rapid changes to incentive programs – has contributed to a lack of capacity in alternative energy industries. There are a limited number of energy auditors and installers for particular types of alternative energy systems, and without stable, consistent programs and a long-term commitment to government incentives, the number of available professionals may shrink.[117]

ECO Comment

The layout of a community determines, in large part, its energy usage. An overarching concern of the ECO is the failure to plan for energy efficiency at the neighbourhood level. Since energy planning, particularly for alternative energy systems, largely focuses on individual residential units, there are few expectations for improving the energy efficiency of a subdivision as a whole. Moreover, energy planning in Ontario has conventionally been done in silos, with the planning of gas supply separate from electricity supply, with distribution separate from transmission, and with all energy systems separate from land use, transportation and water.[118] Energy use has been an unplanned consequence of land use planning decisions, rather than being taken into account in an integrated way from initial planning stages.[119]

To achieve broad-scale change, Ontario cannot continue to treat the implementation of alternative energy systems on a one-off, project-by-project basis.

To achieve broad-scale change, Ontario cannot continue to treat the implementation of alternative energy systems on a one-off, project-by-project basis. Planning for alternative energy and energy use should be integrated with community planning at the neighbourhood and landscape scale.[120] This would further the uptake of alternative energy systems when neighbourhoods are being built. All alternative technologies can benefit when a neighbourhood focus is used. For example, solar technologies benefit from better neighbourhood layout that improves house orientation and layout for solar energy capture, and geoexchange and combined heat and power benefit from economies of scale that arise from building larger systems that can serve multiple units. Organizations such as Quality Urban Energy Systems of Tomorrow and the Canadian Urban Institute, along with government and agency partners, have been examining ways of integrating energy planning with community design.[121]

Another challenge is creating real value in the form of higher sale prices for homes with alternative energy technologies. An unexploited opportunity exists in the as yet unproclaimed provision in the *Green Energy Act, 2009* that would make home energy ratings mandatory at the time of sale of a property. As noted in the ECO's Annual Energy Conservation Progress Report - 2009 (Volume Two), mandatory energy ratings build capacity and assist market transformation to a high efficiency residential sector. The ECO again urges the government to remove barriers to alternative energy and enact this important provision.

8.2 Solar PV vs. Solar Thermal: A Perverse Consequence of Ontario's microFIT Program

The Ministry of Energy claims on its website that "the Ontario Government has some of the most attractive incentives in the world for solar water and air systems."[122] Sadly, this is no longer true, since all of the province's incentive programs have been discontinued and the government has no plans to offer incentives to install solar thermal systems in single family residences.[123]

- **PowerHouse** was a loan and rebate pilot program funded by the Ministry of Energy that offered zero-interest loans or rebates for residential installations of solar thermal, PV, geothermal and wind turbine systems completed by February 15, 2009.[124]
- The **Solar Energy Systems Rebate,** offered by the Ministry of Revenue, returned the Retail Sales Tax paid on solar energy systems to homeowners or builders who installed, expanded or upgraded a qualified solar energy system – including a solar thermal system – in residential or multi-residential premises between November 26, 2002 and December 31, 2009.
- The **Ontario Home Energy Savings Program (HESP)** was introduced in April 2007 to provide residential rebates of up to $5,000 for energy efficiency retrofits – including up to $1,250 for the installation of a solar domestic hot water system – and reimburse homeowners for 50 per cent of the cost of a home energy audit. The retrofit component of the program, which matched the rebates offered by the federal ecoENERGY rebate program, ended April 2011. The program will continue to fund home energy audits, however, until April 2012.

ECO Comment

Although the provincial government no longer offers homeowners incentives to install solar thermal systems, it does provide – through the OPA – an enticing incentive for installing solar PV systems: the microFIT program. As noted in the ECO's Annual Energy Conservation Progress Report – 2009 (Volume Two), Ontario's microFIT program is an important tool for developing renewable energy sources[125] and will help the province phase out coal-fired electricity.

When combined with the recent discontinuation of solar thermal programs, however, the microFIT program creates a perverse incentive for homeowners to use their limited roof space and capital dollars to outfit their homes with solar PV rather than solar thermal systems.[126] This is unfortunate because solar thermal systems, which use solar energy directly rather than convert it into electricity, are generally more energy efficient and deliver greater energy (and cost) savings than solar PV. Moreover, because most Ontario homes rely on fossil-fuelled heating, solar thermal systems can more effectively reduce GHG emissions.[127]

The government's unintended favouritism for solar PV over solar thermal brings into question whether the government prioritizes generating renewable electricity over conserving energy and reducing overall GHG emissions. (This apparent focus on electricity generation – rather than energy conservation and GHG reductions – mirrors the Long-Term Energy Plan's myopic emphasis on electricity.) Unfortunately, without a comprehensive energy plan, there is little evaluation of what initiatives would best reduce GHG emissions.

In June 2007, as part of its "Go Green" climate change strategy, the government announced that it would help equip 100,000 homes with solar power.[128] At the same time, a Solar Task Force was created to provide advice on how to achieve this target. This task force was launched in February 2008 with a focus on residential solar hot water systems, which were considered by the government to be "a key element in achieving the target."[129] In October 2008, the Solar Task Force completed its report and made many recommendations, a number of which have not yet been fulfilled and could still be implemented to move closer to the government's 100,000 solar roof target.

Examples of these recommendations include:

- Permanently exempting solar hot water systems from provincial sales tax;
- Providing a zero-interest loan program across the province; and,
- Allowing municipalities to use local improvement charges for supporting renewable energy improvements on private property.[130]

While solar PV is a generation measure and solar thermal largely a conservation measure, both types of technologies have value and should be promoted through incentives to meet government goals, including reducing GHG emissions. To this end, the government could resurrect the effective and popular HESP, which provided more than $1.3 million between 2007 and 2011 to help finance more than 1,100 solar domestic hot water systems. Uptake in this particular component of the program had grown enormously by the program's last year.[131]

Moreover, to reverse the favouritism for solar PV caused by the microFIT program, the government may have to adjust the solar PV tariff so as not to compete with the financial benefits of installing solar thermal systems. Previously, the ECO commended the OPA for establishing a microFIT program advisory panel to provide advice on program development.[132] At the time, the ECO suggested that the panel should address the evolution of microFIT tariffs, and review the experience of other jurisdictions' feed-in tariffs for guidance. Given the current circumstances, the panel could examine whether the province is favouring solar PV in applications where solar thermal would be better from a GHG reduction perspective.

Finally, the government could consider implementing a feed-in tariff for renewable heat, as has been proposed in the United Kingdom (UK). With feed-in tariff schemes already in place that encourage the generation of renewable electricity, in March 2011, the UK government announced plans to improve the limited support afforded to renewable heating by introducing a Renewable Heat Incentive policy.[133] This policy is the first financial support scheme for renewable heat of its kind in the world and will provide long-term financial support to renewable heat installations, including residential solar thermal systems, thus "making renewable heat not just an environmentally sound decision, but also a financially attractive one."[134]

The ECO recommends that the Ministry of Energy adjust the relative financial incentives available for solar thermal and solar photovoltaic in residential buildings to appropriately reflect the economic and environmental benefits of each technology.

Appendix A:
Examples of Alternative Energy Systems

District energy is an underground energy distribution system that delivers thermal energy to buildings from a central plant. Although not strictly an "alternative energy" system, single district energy installations heat or cool several buildings or homes and so are generally more efficient and produce lower emissions than traditional heating and cooling systems.[135]

District energy is often associated with **combined heat and power** (cogeneration), which produces both electricity and heat (as steam) from a single fuel. Cogeneration systems recover heat that would normally be wasted in an electricity generator, and save fuel that would otherwise be used to produce heat or steam in a separate unit.

Geoexchange technology uses the relatively constant temperature beneath the surface of the earth (between 4°C and 10°C year-round) to heat and cool buildings.[136] Geoexchange systems require either a circuit of underground piping (closed loop) or water from a well (open loop),[137] as well as a heat pump and a distribution system within the building. In the winter months, heat is pumped from the ground into the building; in summer months, this is reversed and heat is pumped from indoors into the ground, which acts as a heat sink. Although some electricity is required to operate the heat pump, practitioners estimate three to four equivalent units of free thermal energy is produced from every one unit of electricity used.

Traditionally, the term **geothermal energy** described geologically deeper and higher temperature resources used for electricity generation in residential and commercial applications, which recover waste heat from their operations.[138] However in recent years, the term has been used to describe a broader spectrum of geothermal energy resources including geoexchange systems.

Passive solar refers to a system that collects, stores, and redistributes solar energy without the use of fans, pumps, or complex controllers. Passive solar makes use of the sun's energy, usually as it enters through south-facing windows, by storing heat in a "thermal mass" such as walls or floors made of stone or steel.[139] This heat can significantly reduce the amount of additional mechanically-produced heat required. Passive solar design can be used in combination with any type of conventional or alternative space heating system. Despite Ontario's cold winters, passive solar has proven to be successful at greatly reducing residential space heating load.[140]

Since access to adequate sunlight is required for successful passive solar design, street orientation and spacing between houses are key factors in passive solar efficiency.[141] Streets running east to west, where houses have large south-facing facades with windows unobstructed by neighbouring buildings, are ideal for maximum access to winter sun and lower levels of heat from sun in the summer.

Solar photovoltaic (PV) cells transform the sun's energy into electricity, which is then used as an energy source. Unlike other technologies described above, this high-grade electricity can be used, in addition to heating needs, to power appliances and lights.

Solar thermal is a type of active solar technology used for space or water heating that collects solar energy in the form of heat and transfers the heat directly to air or a heat-transfer fluid. The use of fans or pumps is required to move the heat for direct use or for storage. All buildings need to bring in outside air for health reasons, and in winter if this air is preheated using solar thermal technology before moving indoors, significant amounts of energy can be saved.

Endnotes

Endnotes

1. Environmental Commissioner of Ontario, *Annual Energy Conservation Progress Report – 2009 (Volume One): Rethinking Energy Conservation in Ontario* (Toronto, Ontario: 2010), 6 which contains a full description of the reporting mandate and approach.

2. EB-2008-0346, Demand-Side Management (DSM) Guidelines for Natural Gas Distributors.

3. There was no significant new activity. Most activities reflected implementation of previously committed funding, programs and policies (e.g., transit, electric vehicle rebates, freight trucking) or reduction and re-scoping of existing programs (e.g., Green Commercial Vehicle Program, Long Combination Vehicles, Ontario Bus Replacement Program).

4. Environmental Commissioner of Ontario, *Annual Report 2008/2009*, 4-5 which contains a discussion of resilience.

   Homer-Dixon, Thomas, *Complexity Science and Public Policy*, John L. Manion Lecture, May 5, 2010 contains a discussion of the concepts and ideas of complexity theory.

5. Ontarians are told by some groups that conservation is costly even though it can help lower bills; information about the cost of building new nuclear supply is not provided; the possibility of lower costs for renewable energy as the technology matures is ignored; smart grid costs are not put in context of new business opportunities and consumer benefits.

6. Government of Ontario, *Ontario's Long-Term Energy Plan: Building Our Clean Energy Future* (Toronto, Queen's Printer for Ontario, 2010).

7. Government of Ontario, *Ontario's Long-Term Energy Plan: Building Our Clean Energy Future* (Toronto, Queen's Printer for Ontario, 2010), 15,19, figures 4 and 5.

   Somewhat confusingly, the text of the LTEP states that 165 TWh of generation will be supplied in 2030 while Figure 5 puts generation at 198 TWh. Even netting out the 14 per cent conservation amount in Figure 5 would mean about 170 TWh generated in 2030. The difference may be due to about 5 TWh of power generated in Ontario but exported and not consumed in the province.

8. The LTEP considers conservation as megawatts of installed capacity – a supply resource reported on the same footing as generation (energy analysts refer to these as "negawatts"). Conservation capacity is not "netted out" of total capacity (including conservation) before calculating installed resources. In 2010, installed conservation capacity is reported as 1,837 MW or 5 per cent of total capacity and it will nearly triple by 2030 to 7,156 MW or some 15 per cent of capacity. Similarly in calculating electricity amounts generated by fuel type, terawatt-hours of conservation are also not netted out. In 2010, conservation provided nearly 6 TWh or 4 per cent of supply and this will grow to about 28 TWh or almost 14 per cent of supply in 2030

9. Ontario Ministry of Energy, e-mail to ECO, April 15, 2011.

10. There is installed natural gas capacity associated with Non-Utility Generator (NUG) contracts provided by generators since the 1990s. During this decade, many of the contracts will expire and the OPA will decide if their generation is still needed and whether new contracts will be signed with NUGs.

11. Ontario Ministry of Energy, e-mail to ECO, April 15, 2011.

    The specific amounts are as follows. Coal currently accounts for 12 per cent or 4,484 MW of installed capacity producing over 13 TWh or 8 per cent of total generation in 2010. Installed natural gas generation capacity is currently 9,424 MW or 25 per cent of total capacity. In 2030, gas-fired capacity will be 9,153 MW and it will account for 19 per cent of the 2030 total capacity. In 2010, gas-fired generators supplied nearly 23 TWh or about 15 per cent of generation. Gas-fired generation will decline and it will contribute only about 15 TWh or seven per cent of total generation in 2030. Nuclear power currently represents 31 per cent of capacity with 11,446 MW installed. It supplied 52 per cent or nearly 82 TWh of power generated in 2010. Nuclear will provide about 45 per cent of supply (some 90 TWh) in 2030. An installed capacity of 12,052 MW (25 per cent of total capacity) will be needed to provide this amount of power.

    Electricity generated from renewable sources (wind, solar and bio-energy) accounted for 1,657 MW or 5 per cent of total installed capacity in 2010 and supplied nearly 4 TWh or 2 per cent of total generation. By 2030, this will grow to nearly 10,700 MW comprising 22 per cent of total capacity. Some 26 TWh or 13 per cent of total generation will be provided by renewables (other than hydro). Hydroelectric power will grow slightly from the current 8,127 MW (22 per cent of total installed capacity) which provided 39 TWh or 19 per cent of generation. By 2030, an installed capacity of 9,024 MW (19 per cent of total capacity) will provide over 40 TWh or 20 per cent of total generation. Conservation, at 1,837 MW, currently accounts for 5 per cent of 'installed capacity." It will nearly triple by 2030 to 7,156 MW or 15 per cent of capacity. In 2010, conservation provided nearly 6 TWh or 4 per cent of supply and this will grow to about 28 TWh or almost 14 per cent of supply in 2030.

12. Ontario Power Authority, *Integrated Power System Plan, version 080904, August 29, 2008* http://www.powerauthority.on.ca/integrated-power-system-plan/b-ipsp (accessed April 1, 2011).

13. Ontario Regulation 424/04, Integrated Power System Plan http://www.e-laws.gov.on.ca/html/regs/english/elaws_regs_040424_e.htm

14. Ontario Ministry of Energy, "McGuinty Government Seeking Citizens' Views On Electricity Supply Mix," News Release, February 2, 2006. http://news.ontario.ca/archive/en/2006/02/02/McGuinty-Government-Seeking-Citizens039-Views-On-Electricity-Supply-Mix.html

    In February 2006, the Ministry of Energy held 12 town hall meetings across Ontario and invited the public to comment on its web site on the future supply mix of Ontario's electricity sector prior to development of the IPSP. The planning documents underlying this consultation were based on the *Supply Mix Advice Report*, drafted by the OPA, which presented options for the future development of the electricity system. http://www.powerauthority.on.ca/integrated-power-system-plan/supply-mix-advice

15. Ontario Ministry of Energy, "McGuinty Government Invites Feedback from Ontarians," News Release, September 20, 2010. http://news.ontario.ca/mei/en/2010/09/ontario-to-update-long-term-energy-plan.html

    Ontario Ministry of Energy, "Seeking Ontarians' Views on Our Energy Future," News Release, September 20, 2010. http://news.ontario.ca/mei/en/2010/09/seeking-ontarians-views-on-our-energy-future.html

    Although news releases used the term "update", strictly speaking there was no previous long-term energy plan to update. News releases confused the matter as they stated that the first version of the long-term plan dated from 2006. There was no LTEP issued in 2006 but there was an Integrated Power System Plan (IPSP) that was requested by the Minister of Energy in June 2006. Also, news releases described the LTEP as an updated IPSP and referred to targets contained in the 2007 IPSP as achievements made under the LTEP.

16. The questions were: (1) After several years of stable rates, electricity prices for Ontarians are increasing now due to investments in infrastructure and new generation. How should increased costs to Ontarians be weighed against other goals in power system planning like modernizing infrastructure, building new generation and increasing renewable energy production while phasing out dirty coal generation? (2) How do you think the electricity demands of families and businesses will change over the next 20 years in Ontario? (3) What role should renewable forms of energy like hydro, solar, wind and biomass play in Ontario's future supply mix? (4) What type of generation should replace dirty coal in Ontario's supply mix? (5) What role should natural gas play in Ontario's future energy supply? (6) What role should nuclear power play in Ontario's future supply mix? (7) What is the appropriate and cost effective level of investment in transmission and distribution – the infrastructure that carries power from stations and delivers it to our homes and businesses – to target in our future power grid? How should we balance the needs of cost effectiveness with ensuring appropriate build-out? (8) Are Conservation and Demand Management (CDM) programs, that provide tools to help manage bills and avoid new system costs, important to Ontario's energy future? Are there ways to enhance them? (9) What key elements do you think should be considered to ensure that Ontario's energy system remains reliable, sustainable, clean and cost-effective for our children and grandchildren?

17. Environmental Registry posting # 011-1701.

18. Minister of Energy Brad Duguid, Directive to the Ontario Power Authority, February 17, 2011. http://www.powerauthority.on.ca/sites/default/files/new_files/IPSP%20directive%2020110217.pdf (accessed April 15, 2011).

    Minister of Energy Brad Duguid, Letter of Direction to the Ontario Energy Board, February 17, 2011. http://www.ontarioenergyboard.ca/OEB/_Documents/Documents/Direction_to_the_OEB_20110217_IPSP.pdf (accessed April 15, 2011).

    The finalized Supply Mix Directive was transmitted to the OPA on February 17, 2011. It replaced the Supply Mix Directives issued in June 2006 and September 2008, and directed the OPA to prepare an Integrated Power System Plan pursuant to the goals set out in the Supply Mix Directive.

    A letter of direction was also issued by the government to the Ontario Energy Board advising that it is anticipated that the OPA would deliver the Integrated Power System Plan later in 2011, and the Board must carry out the review no later than 12 months after the date that the OPA submits the plan to the Board.

19. Minister of Energy Brad Duguid, Directive to the Ontario Power Authority, February 17, 2011. http://www.powerauthority.on.ca/sites/default/files/new_files/IPSP%20directive%2020110217.pdf (accessed April 15, 2011).

The Supply Mix Directive states that it replaces the previous two directives. Clarification was added to the final Supply Mix Directive in the section directing that new transmission capacity be built in several regions of the province. It was specified that the OPA should recommend the scope and timing of new transmission investment.

20. One megawatt equals 1,000 kilowatts and 1 terawatt-hour equals 1 billion kilowatt-hours.

21. Ontario Power Authority, *Integrated Power System Plan, version 080904, August 29, 2008*, Exhibit D, Tab 5, Schedule 1. http://www.powerauthority.on.ca/sites/default/files/page/7764_D-5-1_updated_2008-09-04_v2.pdf (accessed April 15, 2011).

    Minister of Energy Dwight Duncan, Directive to the Ontario Power Authority, June 13, 2006. http://www.powerauthority.on.ca/sites/default/files/page/1870_IPSP-June13,2006.pdf (accessed April 15, 2011).

    The 2010 target was to increase by 2,700 MW from a 2003 base of 7,702 MW to a total 10,402 MW.

22. Ontario Ministry of Energy, e-mail message to ECO staff, March 11, 2011.

    No source document was provided by the Ministry of Energy.

23. Minister of Energy and Infrastructure Brad Duguid, Directive to the Ontario Energy Board, March 31, 2010. http://www.ontarioenergyboard.ca/OEB/_Documents/GEGEA%20Implementation%20and%20Readiness/minister_directive_20100423.pdf (accessed April 27, 2011).

    The targets were established for the period January 1, 2011- December 31, 2014.

24. Minister of Energy and Infrastructure Brad Duguid, Directive to the Ontario Energy Board, March 31, 2010. http://www.ontarioenergyboard.ca/OEB/_Documents/GEGEA%20Implementation%20and%20Readiness/minister_directive_20100423.pdf (accessed April 27, 2011).

    Section 2(a) of the CDM Directive simply states the target as 1,330 MW of provincial peak demand. Section 6(g) states that LDCs should use the OPA's EM&V protocol when verifying their program savings. The OPA's Protocol appears to define peak demand to include winter and summer peaks. Other definitions of peak are used for CDM programs or in regulations (e.g., industrial demand response programs and critical peak pricing for consumers with demand greater than 5 MW). For example, peak could be defined as the all-time highest hour in 2014, or as an average of a certain number of the highest hours in 2014).

25. The ministry was unable to provide detailed supporting documentation in response to information requests made by the ECO, claiming that they were not the custodian of the information requested. As a result, several of the claimed quantities remain obscure. For example, the LTEP claims that the conservation targets will save ratepayers $27 billion over 20 years based on a $12 billion investment, that the $3 billion invested in conservation programs over the next five years will result in avoided supply costs of $10 billion, that over 1,700 MW of conservation savings have been achieved to date.

26. Baseload generation refers to generating stations that are operated to the greatest extent possible and run all the time because they are expensive or technically complex to shut down for short periods. Baseload generators provide some or all of the minimum load of a system and produce electricity at an essentially constant rate running continuously, maximizing system efficiency and minimizing system operating costs. An example of a baseload generator is a nuclear plant.

    Both types of targets provide planning discipline. Peak demand targets, as the name implies, help avoid building new peaking stations, typically gas-fired plants. Consumption-based targets are directed more toward reducing the need for additional baseload and intermediate generating stations.

    Recently, Ontario has experienced periods of surplus baseload generation. This is mainly a result of two drivers: reduced demand resulting from the financial crisis of 2008 and to a lesser extent, recently added renewable capacity like wind and solar generators that supply electricity whenever their output is available and are not dispatched by the IESO.

    Conservation has not been a significant contributor to surplus baseload conditions because Ontario's programs to date have been demand response programs that target peak load, not baseload.

    Excess baseload results in inefficient prices, but importantly for system planning, reduces flexibility needed for operating Ontario's fleet of generators. Flexibility will be important as the renewable capacity set out in the LTEP comes on stream and the IESO develops rules to require that renewable generators be dispatchable. (When generators are dispatchable, this means that they can be turned on or off in a matter of minutes upon demand by the IESO in contrast to base

load generators which have limited capability to adjust their power output and are not controlled by the system operator).

27. Ontario Power Authority , *Integrated Power System Plan, version 080904, August 29, 2008*, 3, 18, Exhibit D, Tab 6, Schedule 1. http://www.powerauthority.on.ca/sites/default/files/page/7764_D-5-1_updated_2008-09-04_v2.pdf (accessed April 15, 2011).

    A range of capacity was established because the amount of new nuclear needed was affected by decisions on which existing nuclear plants would be refurbished. Two planning scenarios were developed to cover the range of expected new baseload. The nuclear build was to begin in 2018.

28. Government of Ontario, *Ontario's Long-Term Energy Plan, Building Our Clean Energy Future* (Toronto, Queen's Printer for Ontario: 2010), 24.

29. Government of Ontario, *Ontario's Long-Term Energy Plan, Building Our Clean Energy Future* (Toronto, Queen's Printer for Ontario: 2010), 18, figure 4.

    The LTEP could have better communicated this aspect of conservation as a "capacity resource": the role it plays in avoiding the need to build additional generation and transmission. There are frequent references to conservation savings being the equivalent to powering a city of a certain size or removing a number of homes from the grid or vehicles from the road. For example, the LTEP's 2030 conservation target of 7,100 MW and 28 TWh is described as the equivalent of taking 2.4 million homes off the grid. The point would be better and more directly made by advising Ontarians that this will mean Ontario can avoid building say 8 new nuclear reactors.

30. A "loading order" formally establishes that a jurisdiction, in planning to meet its energy needs, will invest first in energy efficiency and demand-side resources, followed by renewable resources, and only then in clean conventional electricity supply.

31. For example, the Plan commits Ontario to two new nuclear units and states nuclear power must be provided at a fair price. In discussing a process to procure two new nuclear plants at Darlington undertaken in 2008, the Plan states that the bid price received exceeded the Province's target price. No information on the price to build new nuclear is provided in the LTEP so that the price of new nuclear build can be compared against other forms of generation, particularly renewable generation which opponents claim is a premium priced supply option. Although there is a directional shift to renewable generation, constraints on building new transmission may significantly limit construction of all the renewable generation proposed in the Plan. Growth of the nuclear industry has stalled in the past two decades in no small part because of high capital costs for construction of new units and refurbishment of existing units.

32. To date, in considering applications by LDCs for Board-Approved CDM programs, the OEB has signalled that it requires all elements of the program – design, delivery and evaluation – to be thoroughly detailed prior to granting approval. The Board will approve a program in its totality and not piecemeal. This may slow the introduction of programs into the market and result in missed targets. A recent OEB decision on natural gas DSM indicates that the Board strongly values ratepayer impacts when balancing its mandate to promote conservation and approve prudent rates.

33. Robert Warren, Ian Mondrow, George Vegh and Jan Carr, "Where is the Regulatory System Headed," *Ippso Facto*, August 2010: 12.

    George Vegh, Glenn Zacher and Patrick Duffy, "The Changing Face of Regulation," *Ippso Facto*, January 2009: 8.

    The commentaries provide a thought provoking discussion of the role of the OEB and government in this matter. An example of actions that have affected the scope and pace of CDM is provided by negotiations between the OPA and LDCs on master contracts and schedules for new OPA-Contracted Province-Wide CDM programs (to begin January 1, 2011) and are still not complete at the time of writing this report.

34. Natural gas conservation receives a single mention in relation to a program being designed for low-income households

35. The Plan should have provided a detailed discussion of specific elements like minimum efficiency standards for appliances, building codes and ratings, official municipal plans, district energy, carbon pricing. Brief mention is made of one specific regulation to require the public sector (MUSH – municipalities, universities, schools and hospitals) to produce conservation plans. There is a promise of support to homeowners for energy audits and a cursory statement that conservation targets will be met through codes, standards, programs and time-of-use rates.

36. A formal collaborative effort of government, energy agencies, regulators and utilities articulates a single, unified approach to electricity and gas use describing a common implementation plan to meet policy goals. California's planning approach recently integrated

transportation energy use, research and development needs and statutory commitments on climate change like cap-and-trade policy, and is considering the need to integrate local government decisions on planning, infrastructure and approvals given to developers.

There are parallels to Ontario's regulatory framework that uses directives and the IPSP. The implementation plan integrates the California Governor's Executive Orders, the Public Utilities Commission and Energy Commission proceedings, and legislative direction. Some of the areas for coordination and integration are minimum energy performance standards, consumer appliance purchases, energy efficiency and demand response programs, consumer investment in distributed energy, such as solar thermal and photovoltaic systems, and building codes.

37. A similar point could be made concerning electric cars. A literal reading of the Supply Mix Directive would suggest that an initiative designed to reduce purchases of electric cars would be a worthwhile conservation measure to fund, as it would reduce total electricity consumption. Yet it is unlikely that this is actually the government's preference, given its other actions to promote electric cars.

38. Ontario Ministry of Revenue, "Northern Ontario Energy Credit", http://www.rev.gov.on.ca/en/credit/noec/index.html (accessed May 2, 2011).

39. Ontario Ministry of Revenue, "Ontario Energy and Property Tax Credit", http://www.rev.gov.on.ca/en/credit/oeptc/index.html (accessed May 2, 2011).

40. An appropriate monthly amount might be 10 per cent of the "all-in" price of 800 kWh of electricity in 2010, which would be approximately $11.40 per month.

41. Aegent Energy Advisors Inc., "Ontario Clean Energy Benefit - A Short-Term Conservation Killer?", http://www.aegent.ca/newsletters/OntarioCleanEnergyBenefit.html (accessed May 2, 2011), newsletter, November 2010.

42. Electric Power Research Institute, *Price Elasticity of Demand For Energy: A Primer and Synthesis* (2008), 20.

43. Ontario Energy Board, *Regulated Price Plan Price Report, November 1, 2010 to October 31, 2011* (2010), 22.

44. The five peak hours must fall on five different days.

45. Independent Electricity System Operator, "Allocation of Global Adjustment" (presented to Stakeholder Advisory Committee, March 31, 2010), http://www.ieso.ca/imoweb/pubs/consult/sac/sac-20100331-Allocation-of-Global-Adjustment.pdf (accessed May 2, 2011).

46. Ontario Ministry of Energy, information provided to the ECO in response to ECO inquiry, March 16, 2011. The base period is the time period over which the five system peak hours (and the demand of Class A consumers during these peak hours) is determined. In this example, the base period was from May 1, 2010 to October 31, 2010. Going forward, the base period will be 12 months in length.

47. Independent Electricity System Operator, "Diverse Supply Mix Provides Flexibility in Operating Ontario's Power System - Integration of Renewable Resources Well Underway", News Release, January 7, 2011. The 2010 values for Ontario electricity consumption (142 TWh) and weighted average Global Adjustment (2.73 cents/kWH) reported in this news release mean that the total Global Adjustment cost in 2010 was $3.88 billion. Four per cent of this value is $155 million.

48. Ontario Regulation 494/10 - Amending O.Reg. 95/05, made under the *Ontario Energy Board Act, 1998*.

49. Environmental Commissioner of Ontario, *Annual Energy Conservation Progress Report – 2009 (Volume Two): Re-thinking Energy Conservation in Ontario - Results* (Toronto, Ontario: 2010), 21.

50. The Brattle Group, *Assessing Ontario's Regulated Price Plan: A White Paper* (2010), 8-9.

51. Ontario Energy Board, letter, March 31, 2011. "Re: Review of the Structure and Price Setting Methodology for Time-of-Use Prices; Staff Report to the Board. Board; File No.: EB-2010-0364".

52. The predictions in the report by the Brattle Group were based on two Ontario pilot studies with small sample sizes, and these studies varied by almost a factor of 10 in their estimates of how much TOU pricing would reduce peak demand (p. 8).

53. Ontario Ministry of Energy, information provided to the ECO in response to ECO inquiry, March 16, 2011.

54. Ontario Ministry of Municipal Affairs and Housing, *Suite Metering Provisions Under the Residential Tenancies Act, 2006 and the Energy Consumer Protection Act, 2009 Consultation Paper* (2010).

55. Section 53.18 of the *Electricity Act, 1998* included a prohibition on "discretionary metering" after November 2005, unless specific authorization was received. The government clarified (through O. Reg. 442/07 under the *Electricity Act, 1998)* that condominium corporations could enter into suite metering arrangements, but similar rules for the rental sector were never provided. To confuse matters further, section 137 of the *Residential Tenancies*

Act, 2006 included rules describing the conditions under which suite meters could be introduced into rental residential units, but this section of the Act was never brought into force. An Ontario Energy Board decision and order (EB-2009-0111) in August 2009 provided explicit authorization for suite metering (specifically, sub-metering) under certain conditions, with the understanding that these rules would soon be superseded by the *ECPA* and supporting regulations.

56. Ontario Energy Board, *EB-2009-0111, Decision and Order* (2009).

57. Navigant Consulting, *Evaluation of Individual Metering and Time-of-Use Pricing Pilot* (2008).

58. New York State Energy Research and Development Authority, *Residential Electrical Submetering Manual* (2001), 2.

59. Ontario Power Authority, information provided to the ECO in response to ECO inquiry, March 14, 2011.

60. Guy Raffaele, Ontario Power Authority, e-mail message to ECO staff, March 3, 2011.

61. Ontario Power Authority, information provided to the ECO in response to ECO inquiry, March 14, 2011.

62. Ontario Power Authority, information provided to the ECO in response to ECO inquiry, March 14, 2011.

63. Environmental Commissioner of Ontario, *Annual Energy Conservation Progress Report – 2009 (Volume One): Rethinking Energy Conservation in Ontario* (Toronto, Ontario: 2010), 24-25.

64. For example, low-income CDM programs offered by LDCs from 2005 to 2007 provided the lowest energy savings per dollar spent relative to the suite of CDM programs offered. Similarly, natural gas utilities have shown low-income programs result in relatively poorer performance. Environmental Commissioner of Ontario, *Annual Energy Conservation Progress Report – 2009 (Volume Two): Re-thinking Energy Conservation in Ontario - Results* (Toronto, Ontario: 2010), 39.

65. For example, one stakeholder noted LDCs could be restricted from designing any load control program as it could be considered duplicative to the *peaksaver*® program under the CDM Code's definition of duplication.

66. Ontario Energy Board, *EB-2008-0346 Staff Discussion Paper On Revised Draft Demand Side Management Guidelines for Natural Gas Utilities* (2011), 47 (budget levels), 50 (recommendation). Board staff's recommendation was that budget levels should increase by 2014 to approximately 6 per cent of regulated utility revenues less the cost of purchased gas.

67. Enbridge Gas Distribution Inc., *2012 DSM Framework Development Response to the Report of Concentric Energy Advisors, Review of Demand Side Management (DSM) Framework for Natural Gas Distributors, and Response to the Report of the Pacific Economics Group, "Top Down" Estimation of DSM Program Impacts on Natural Gas Usage* (2010), 19. Union Gas, *Re: EB-2008-0346 – Union's Comments on the "Review of the DSM Framework for Natural Gas Distributors" Report* (2010), 15. Both utilities had suggested an increase slightly less than recommended by Board staff, to 4-6% of regulated utility revenues less the cost of purchased gas.

68. Minister of Energy Brad Duguid, letter (untitled) to Chair of the Ontario Energy Board Howard Weston, July 5, 2010.

69. Ontario Energy Board, letter, March 29, 2011. "Re: Demand Side Management ("DSM") Guidelines for Natural Gas Utilities (EB-2008-0346); Issues for Further Comment", 4.

70. Ontario Energy Board, letter, March 29, 2011. "Re: Demand Side Management ("DSM") Guidelines for Natural Gas Utilities (EB-2008-0346); Issues for Further Comment", 5.

71. Environmental Commissioner of Ontario, *Annual Energy Conservation Progress Report – 2009 (Volume Two): Re-thinking Energy Conservation in Ontario - Results* (Toronto, Ontario: 2010), 2.

72. Environmental Commissioner of Ontario, *Annual Energy Conservation Progress Report – 2009 (Volume Two): Re-thinking Energy Conservation in Ontario - Results* (Toronto, Ontario: 2010), 38.

73. Utilities are required to offer conservation programs to all customer classes, and the funds spent on conservation programs offered to a class are taken only from ratepayers in that rate class. In addition, most conservation programs only fund a percentage of total costs (the major exception being low-income programs), with participants paying for the remainder.

74. The Consumers' Council of Canada and Audrey LeBlanc have asked the Ontario Energy Board to cancel this charge, on the grounds that it is in fact an indirect tax that is unconstitutional in nature. The case is currently before the Board (EB-2010-0184).

75. Environmental Commissioner of Ontario, *Annual Energy Conservation Progress Report – 2009 (Volume One):*

Rethinking Energy Conservation in Ontario (Toronto, Ontario: 2010), 56.

76. Energy is consumed (lost) in the transmission and distribution of electricity from generation to load, primarily from the conversion of electrical energy to heat energy due to line resistance. When electricity flows across transmission lines, the resistance in the wires causes them to heat up, consuming power in the same way as a filament in a light bulb.

77. Ontario Energy Board, *Ontario Electricity Distributor Practices Relating to Management of System Losses*, Regulatory Audit Office, June 23, 2008, 6.

78. Independent Electricity System Operator, *Loss Penalty Factors (SE-40)*, April 10, 2007, 1.

79. Independent Electricity System Operator, *The Ontario Reliability Outlook*, December 2009, 14.

80. North American Electric Reliability Corporation, *Special Report: Accommodating High Levels of Variable Generation*, April 2009, 55.

81. Independent Electricity System Operator, *Stakeholder Engagement Plan SE-91 – Renewable Integration*, November 4, 2010.

82. The Market Rules are available from the IESO under 'Rules, Manuals and Forms', available from: http://www.ieso.ca/imoweb/manuals/marketdocs.asp (as of May 2, 2011).

83. Independent Electricity System Operator, "IESO Selects Participants for Demonstration Project to Provide Regulation Services", News Release, June 29, 2010.

84. Independent Electricity System Operator, "Supply Overview," http://www.ieso.ca/imoweb/media/md_supply.asp (accessed May 2, 2011).

85. Government of Ontario, *Ontario's Long-Term Energy Plan, Building Our Clean Energy Future* (Toronto, Queen's Printer for Ontario: 2010), 19.

86. Independent Electricity System Operator, *Ontario Reserve Margin Requirements 2011-2014 Version 1.0 (IESO_REP_0684)*, December 20, 2010, A-1.

87. The addition of solar electricity will reduce the degree of variability in total renewable electricity output, because solar electricity output is maximized at different times than wind. The addition of more renewable energy sites dispersed across the province will also reduce variability.

88. Government of Ontario, *Ontario's Long-Term Energy Plan, Building Our Clean Energy Future* (Toronto, Queen's Printer for Ontario: 2010), 17.

89. Ontario Energy Board, *EB-2009-0397 – Filing Requirements: Distribution System Plans – Filing Under Deemed Conditions of Licence*, March 25, 2010, 5.

90. Government of Ontario, *2009 Ontario Budget: Confronting the Challenge Building Our Economic Future* (Toronto, Queen's Printer for Ontario: 2009), 26.

91. Ontario Smart Grid Forum, *Modernizing Ontario's Electricity System: Next Steps*, May 3, 2011, 13.

92. Hydro One Network Incorporated, *Development Capital, EB-2009-0096, Exhibit D1, Tab 3 Schedule 3*, July 13, 2009, 22.

93. Ontario Energy Board, *Ontario Electricity Distributor Practices Relating to Management of System Losses*, June 2008, 2.

94. Ontario Energy Board, *Guidelines for Electricity Distributor Conservation and Demand Management EB-2008-0037*, March 2008, 5.

95. Ontario Energy Board, *Ontario Electricity Distributor Practices Relating to Management of System Losses*, June 2008, 9.

96. Standing Committee on Natural Resources, *Combining our energies: Integrated energy systems for Canadian communities* (Ottawa, Ontario: House of Commons, 2009), 1, 18, 19.

97. Norbert Lechner, *Heating, Cooling, Lighting: Sustainable Design Methods for Architects, Third Edition* (New Jersey: John Wiley and Sons Ltd, 2008), 205.

98. Standing Committee on Natural Resources, *Combining our energies: Integrated energy systems for Canadian communities* (Ottawa, Ontario: House of Commons, 2009), 9.

99. L. D. Danny Harvey, "Reducing energy use in the buildings sector: measures, costs, and examples," *Energy Efficiency* 2 (2009): 139.

100. Ontario Power Authority, "2011-2014 Consumer Program," http://archive.powerauthority.on.ca/Storage/118/16582_Consumer_Program_Presentation_100421.pdf (accessed April 11, 2011).

101. Ontario Ministry of Municipal Affairs and Housing, "Building Regulation – Appendix A: Energy Conservation," http://www.mah.gov.on.ca/Page9295.aspx (accessed April 11, 2011).

102. Ontario Ministry of Municipal Affairs and Housing, *A Study of Prescriptive Requirements for EnerGuide 80 in Ontario's Building Code, March 2010*, http://www.mah.gov.on.ca/Asset8297.aspx?method=1 (accessed March 28, 2011).

103. Minister of Energy and Infrastructure George Smitherman, Directive to the Ontario Energy Board, September 8, 2009. http://www.oeb.gov.on.ca/OEB/_Documents/Documents/Directive_to_the_OEB_20090908.pdf

104. Ontario Energy Board, *Decision on a Preliminary Motion, Enbridge Gas Distribution Inc. EB-2009-0172*, December 22, 2009.

105. Minister of Energy and Infrastructure Brad Duguid, Directive to the Ontario Energy Board, March 31, 2010, section 6 (h). http://www.oeb.gov.on.ca/OEB/_Documents/GEGEA%20Implementation%20and%20Readiness/minister_directive_20100423.pdf

106. Toronto Atmospheric Fund and the Toronto Energy Efficiency Office, "Solar Neighbourhoods Pilot Project Report," http://www.solarneighbourhoods.ca/findings.php (accessed March 15, 2011).

107. Government of Ontario, *Provincial Policy Statement, , 2005,* Section 1.8.1 (e): Energy and Air Quality, 14.

108. Ontario Ministry of Municipal Affairs and Housing, "Planning By Design: A Healthy Communities Handbook," http://www.mah.gov.on.ca/Page6737.aspx (accessed March 15, 2011).

109. Ontario Ministry of Municipal Affairs and Housing, "Provincial Policy Statement, 2005 Performance Monitoring Indicators," http://www.mah.gov.on.ca/Page9100.aspx (accessed March 15, 2011).

110. National Academy of Sciences, National Academy of Engineering and National Research Council, *Real Prospects for Energy Efficiency in the United States* (Washington: The National Academies Press, 2010), 99.

111. Hannah Choi Granade, et al., "Unlocking Energy Efficiency in the U.S. Economy," (New York: McKinsey and Company, 2009), 46.

112. Ontario Power Authority, *2011-2014 OPA-Contracted Province-Wide CDM Programs, Consumer Program Summary Guide, October 2010,* 6-7.

113. Ontario Power Authority, "2011-2014 Consumer Program," http://archive.powerauthority.on.ca/Storage/118/16582_Consumer_Program_Presentation_100421.pdf (accessed April 11, 2011).

114. Environmental Commissioner of Ontario, *Annual Energy Conservation Progress Report – 2009 (Volume Two): Re-thinking Energy Conservation in Ontario - Results* (Toronto, Ontario: 2010), 8.

115. Standing Committee on Natural Resources, *Combining our energies: Integrated energy systems for Canadian communities* (Ottawa, Ontario: House of Commons, 2009), 19-20.

116. Colin Andersen, "District Energy: Now's the Time! Financing District Energy to Support Sustainable Community Projects," Ontario Power Authority, http://archive.powerauthority.on.ca/Storage/122/16922_SP-CACDEAFINAL_with_slides.pdf (accessed April 11, 2011).

117. Richard Blackwell, "Temporary policies leave green businesses in limbo: Changing fate of EcoEnergy and offshore wind programs illustrate need for long-term, overall strategy, critics say," *The Globe and Mail*, March 23, 2011.

118. Brent Gilmour, Katelyn Margerm and John Warren, "Hot Spots: Bringing energy to the forefront of municipal planning," *ReNew Canada*, September 10, 2010.

119. Standing Committee on Natural Resources, *Combining our energies: Integrated energy systems for Canadian communities* (Ottawa, Ontario: House of Commons, 2009), 4.

120. Brent Gilmour, Katelyn Margerm and John Warren, "Hot Spots: Bringing energy to the forefront of municipal planning," *ReNew Canada*, September 10, 2010.

121. Brent Gilmour and Julia McNally, "Integrated Energy Mapping in Ontario Communities" (paper presented at the annual conference of the American Council for an Energy-Efficient Economy).

122. Ontario Ministry of Energy, "Solar Thermal – Residential – FAQ," http://www.mei.gov.on.ca/en/energy/index.php?page=solartr_faq#3 (accessed May 17, 2011).

123. Ontario Ministry of Energy, information provided to the ECO in response to ECO inquiry, March 16, 2011.

124. This program, which was implemented by Enersource Hydro Mississauga, Hydro One Networks and Hydro One Brampton Networks, was only available for customers in certain parts of the province.

125. Environmental Commissioner of Ontario, *Annual Energy Conservation Progress Report – 2009 (Volume Two): Re-thinking Energy Conservation in Ontario – Results* (Toronto, Ontario: 2010), 41.

126. Although photovoltaic/thermal hybrid systems can be installed on industrial, commercial, institutional and multi-residential buildings to both generate electricity and use solar energy as heat, large capital costs and limitations on roof space and residential heating systems constrain the utility of hybrids on single-family residential roofs.

127. Ontario Solar Task Force, *Solar Task Force Report* (Toronto, Ontario: 2008), 7.

128. Governement of Ontario, *Go Green: Ontario's Action Plan on Climate Change* (Toronto, Queen's Printer for Ontario: 2007), 19.

129. Ontario Ministry of Energy, "Solar Task Force," http://www.mei.gov.on.ca/en/energy/conservation/?page=solar-task-force (accessed May 17, 2011).

130. Ontario Solar Task Force, *Solar Task Force Report* (Toronto, Ontario: 2008).

131. Ontario Ministry of Energy, information provided to the ECO in response to ECO inquiry, March 16, 2011.

132. Environmental Commissioner of Ontario, *Annual Energy Conservation Progress Report – 2009 (Volume Two): Re-thinking Energy Conservation in Ontario – Results* (Toronto, Ontario: 2010), 43.

133. UK Department of Energy & Climate Change, "World's First Renewable Heat Incentive Launched To Reduce Emissions," News Release, March 10, 2011.

134. UK Department of Energy & Climate Change, *Renewable Heat Incentive*, (London, UK: 2011), 5.

135. Canadian District Energy Association, October 18, 2010, Powerpoint Presentation: Submission of the Canadian District Energy Association to the Ministry of Energy: Ontario's Long Term Energy Plan.

136. Pembina Institute, "Geoexchange: Energy Under Foot," http://pubs.pembina.org/reports/geoexchangefactsheet.pdf (accessed April 11, 2011).

137. Canadian Geoexchange Coalition, "What is geothermal energy?" http://www.geo-exchange.ca/en/earth_energy_definition_p48.php (accessed April 11, 2011).

138. Canadian Geothermal Energy Association, "Geothermal Power versus GeoExchange Heating and Cooling," http://www.cangea.ca/news/archive/geothermal-power-versus-geoexchange-heating-and-cooling (accessed May 3, 2011).

139. Norbert Lechner, *Heating, Cooling, Lighting: Sustainable Design Methods for Architects, Third Edition* (New Jersey: John Wiley and Sons Ltd, 2008), 152-153.

140. For example, in one green model home built in the Waterloo region, passive solar heat alone provides 50 per cent of the space heating load for the building. See: RETScreen International. "Energy efficiency measures - Residential - Passive solar heating." Natural Resources Canada, http://www.retscreen.net/ang/case_studies_psh_canada_toronto.php (accessed February 1, 2011).

141. Norbert Lechner, *Heating, Cooling, Lighting: Sustainable Design Methods for Architects, Third Edition* (New Jersey: John Wiley and Sons Ltd, 2008), 300.

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